

# NEPOOL Participants Committee Report August 2010

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Senior Vice President and Chief Operating Officer

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# Highlights

- **Day-Ahead (DA), Real-Time (RT) Prices and Transactions**
  - July natural gas prices over the period were 2.3% lower while oil prices were 1.4% higher than June 2010 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were up 17.1% from June 2010 averages

Underlying natural gas data furnished by:



# Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)\***
  - July payments total \$19.4M over the period, up \$12.5M from June
  - First Contingency payments total \$16.3M, up \$9.8M from June
    - \$15.9M paid to internal resources, up \$9.4M from June
      - \$1.1M charged to DALO, \$14.8M to RT Deviations
    - \$434K paid to resources at external locations, up \$327K from June
      - \$388K charged to DALO at external locations, \$46K to RT Deviation
  - Second Contingency payments total \$35K
  - Voltage payments total \$2.3M, up \$2.1M from June
  - Distribution payments total \$762K, up \$652K from June
  - NCPC payments as percent of Energy Market value were 2.2%

\* Total includes NCPC payments to eligible resources at external locations.

# Highlights (cont'd.)

- Written comments on the draft Regional System Plan 2010 (RSP10) report are due to ISO by August 5 and will be the focus of the Planning Advisory Committee (PAC) meeting planned for August 12
- The New England East-West Solution (NEEWS) Interstate Reliability Project will also be discussed at the August 12 PAC meeting
- The RSP Public Meeting scheduled for September 16 features a new format with panel discussions

# Eastern Interconnection Planning Collaborative (EIPC)

- EIPC and DOE have agreed to contract terms and an agreement is in place
- Eastern Interconnection 10 year model development is essentially complete and analysis is underway to identify opportunities for improvement
  - A draft report is expected in October
- Stakeholder Steering Committee (SSC) held their first meeting in Chicago on July 15-16 with topics focused on structure and process
  - Discussed need for chairperson from the SSC ranks
  - Discussed SSC work scope
  - Agreed to formation of working groups to support various project efforts as a means of ensuring SSC can manage work scope

# Highlights (cont'd.)

- The lowest Summer Operable Capacity Margin is being calculated for the week beginning September 11<sup>th</sup>.

# Summer 2010 Highlights

# Summer 2010 - Highlights

- Summer 2010 has already seen several hot days, including a heat wave during the week of July 5
  - Week of July 5<sup>th</sup> was an official heat wave
  - Record temperatures set in some areas
  - Peak load of 27,154 MW on July 6 was the 4<sup>th</sup> highest peak in New England
  - Peak load of 26,508 MW on July 7 was the 9<sup>th</sup> highest peak in New England
- Overall, the New England power system performed well

# Summer 2010 - Highlights (cont'd.)

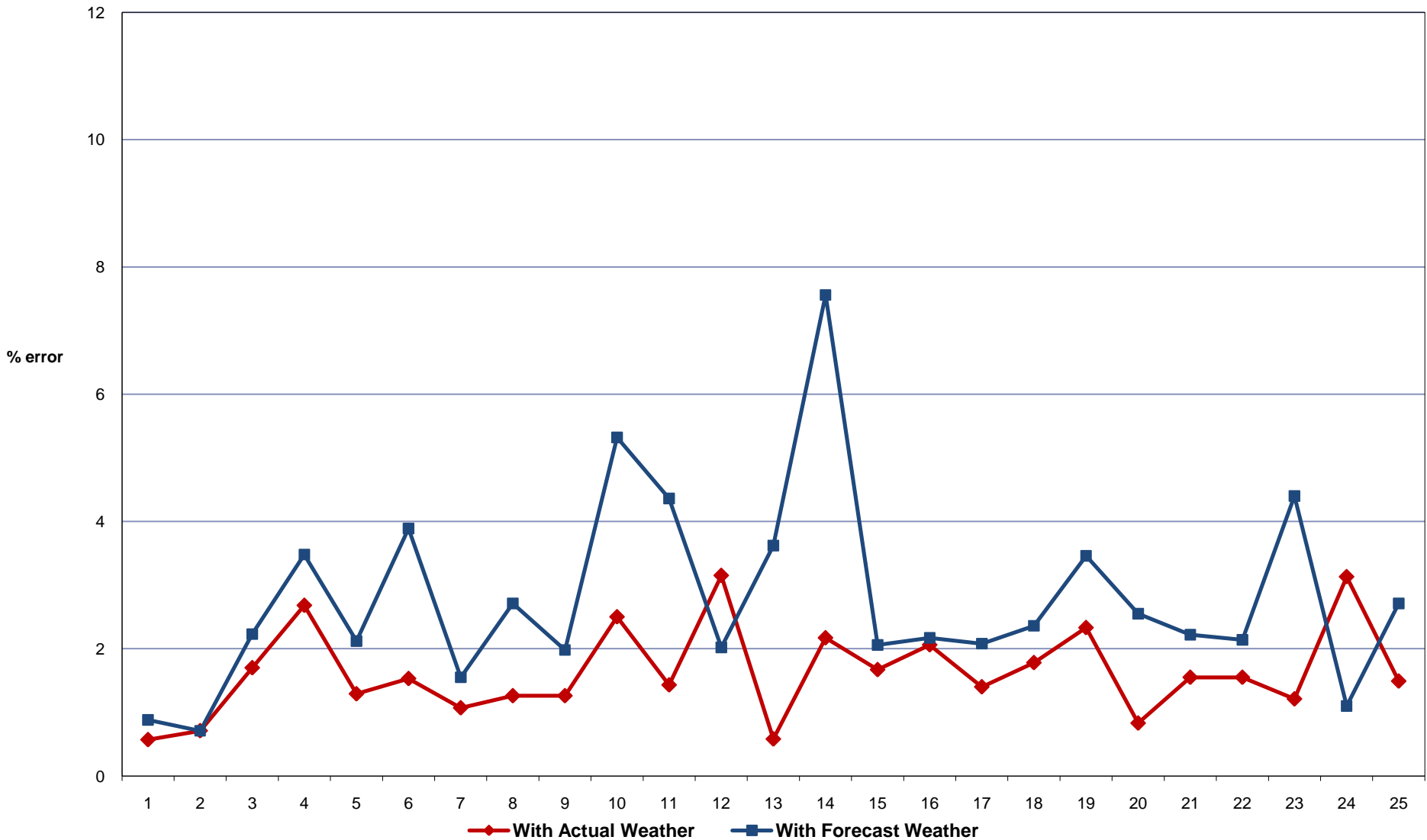
- Summer 2010 also marks the beginning of the first FCM commitment period and full integration of Demand Resources (DRI) into ISO operations
  - Demand Response (~670 MW) was called on June 24 to deal with a system-wide capacity deficiency situation
  - New Control Room applications, communications infrastructure and Operating Procedures and processes for FCM and DRI worked well

# Summer 2010 - Highlights (cont'd.)

- Supplemental commitments have been much higher than in previous months due to the following reasons:
  - Extended outage of the Northfield Mountain station which normally provides significant reserves and load following capability
  - Weather forecast errors which drove load forecast errors (both average daily load forecast and peak daily load forecast)
  - On several days, the day-ahead market cleared lower levels of load than what was required to meet the day-ahead load forecast
  - Sufficient resources need to be committed for reliability day-ahead (during the Reserve Adequacy Assessment) due to the relative inflexibility (start-time) and ramp rate of several units

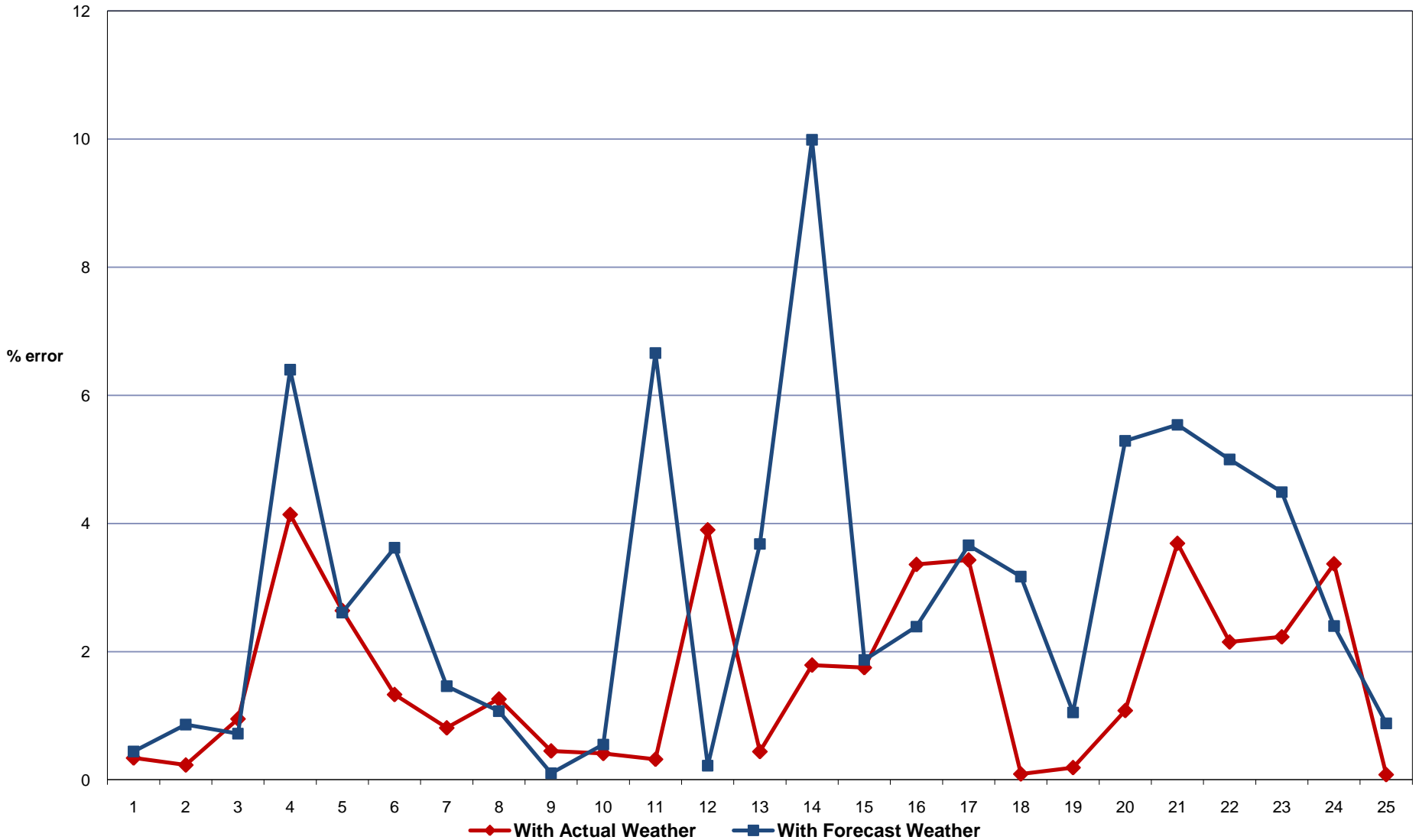
## Daily Average Load Forecast Percent Error for July 2010

**Monthly Average Error with Forecast Weather 2.8% and 1.6% with Actual**

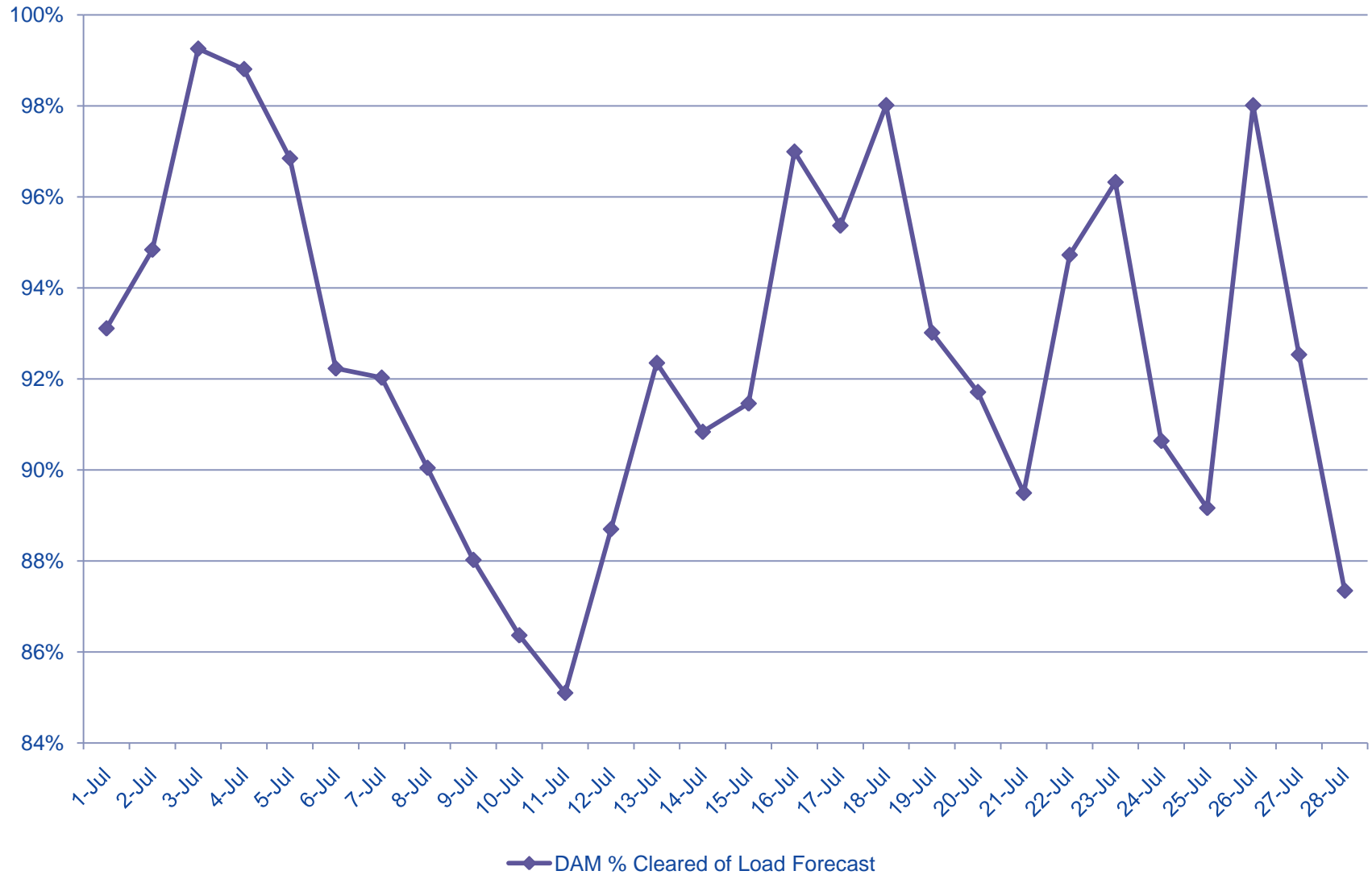


## Load Forecast Percent Error at Hour of Daily Peak for July 2010

### Monthly Average Error with Forecast Weather 3.0% and 1.6% with Actual



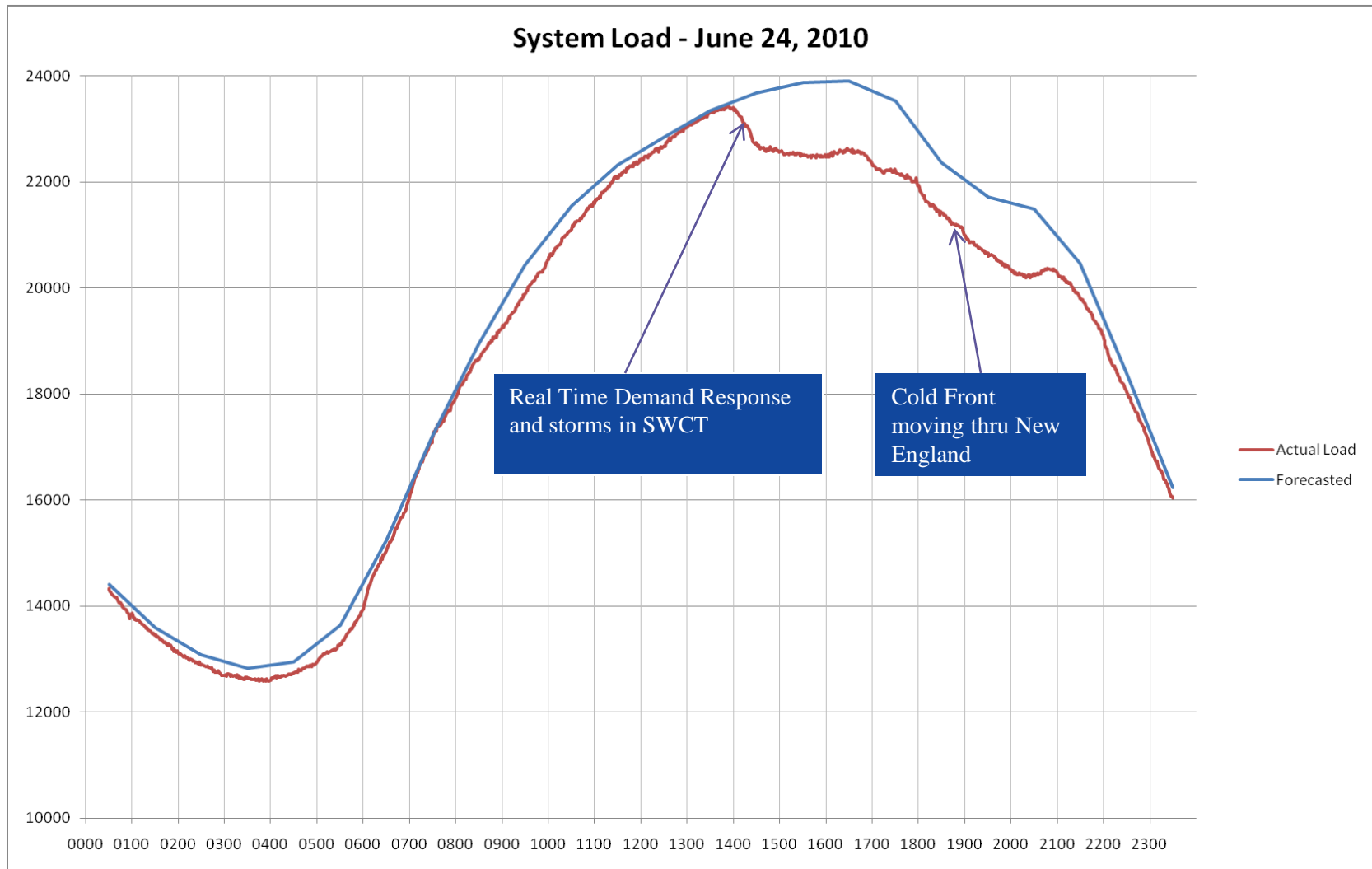
## July 2010 - % of Forecasted Peak Cleared in Day Ahead



# Capacity Deficiency Event #1: Thursday, June 24, 2010

- Operating Procedure #4, “Action During a Capacity Deficiency”, (OP-4) was implemented system-wide due to various generation reductions/outages over the course of the morning and early afternoon
  - Approximately 2000 MW of generator reductions/outages due to mechanical and operational issues
- Forecast peak load on June 24 was 23,900 MW
  - Actual peak load was 23,314 MW

# System Load vs. Forecast



# RTDR Obligation and Performance by Load Zone

Load Zone	Total Capacity Obligation	Average Aggregate Performance*	Percent RTDR Obligation
Connecticut	226.83	170	33.9
West Central Massachusetts	79.59	79	11.9
Northeast Massachusetts	70.74	46	10.6
Southeast Massachusetts	45.23	30	6.8
Rhode Island	27.76	27	4.1
Vermont	23.71	29	3.5
New Hampshire	29.11	33	4.4
Maine	166.22	239	24.8
<b>New England</b>	<b>669</b>	<b>653</b>	<b>100.0</b>

- Additional meter data corrections to address data quality issues will adjust the net performance.
- Additional analysis of individual resource performance is underway.

# Capacity Deficiency Event #2: Monday, July 5, 2010

- OP-4 implemented system-wide due to load running approximately 1350 MW over the load forecast
- Forecast peak load on July 5 of 21,540 MW
  - Actual peak load was 22,903 MW

# System Operations

# System Operations

<b><u>Weather Patterns:</u></b>	Boston	Temperature – Above Average Precipitation – Average	Hartford	Temperature – Much above Avg* Precipitation – Below Average * (8 degrees above normal)
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<b><u>Peak Load:</u></b>	27,154MW	<b>JULY 6, 2010</b>	15:00
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**Minimum Generation Emergencies :** None

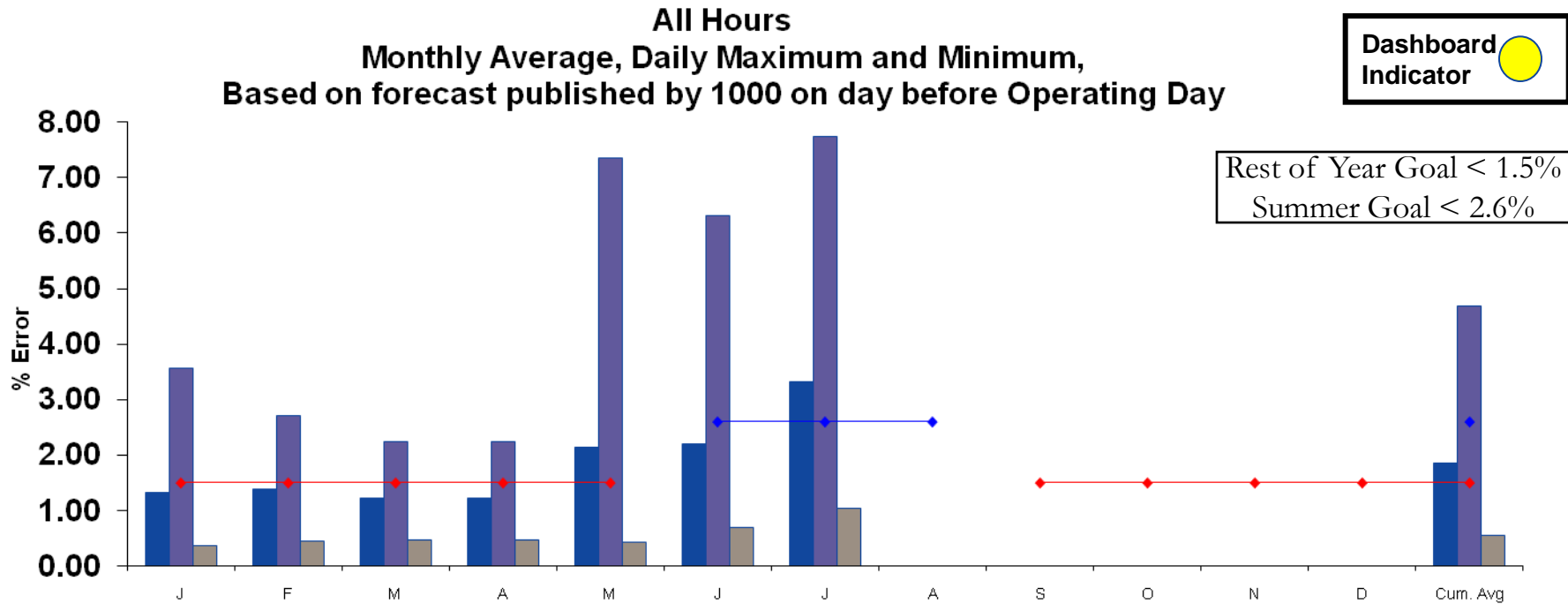
**M/LCC2:**  
07/05 - Due to a Capacity Deficiency, 07/06 – Due to a Capacity Deficiency

**OP-4 :**  
07/05- Due to a Capacity Deficiency, Loads were 1400 MW over the forecasted curve on peak. Lost 350 MW of Generation. Implemented Action 1 only.

**NPCC Shared Activation of Reserve Events:**

July 07	PJM	1101 MW
July 07	NYISO	526 MW
July 21	IESO	940 MW
July 28	IESO	800 MW

# 2010 System Operations - Load Forecast Accuracy



■ Mo. Avg   
 ■ Day Max   
 ■ Day Min   
 ◆ Summer Goal   
 ◆ Rest of Year Goal

	J	F	M	A	M	J	J	A	S	O	N	D	Avg	
Mo Avg	1.33	1.39	1.31	1.23	2.15	2.21	3.32						1.86	Mo Avg
Day Max	3.57	2.72	2.62	2.24	7.35	6.32	7.73						4.68	Day Max
Day Min	0.37	0.45	0.43	0.48	0.44	0.70	1.05						0.56	Day Min
Summer Goal						2.60	2.60	2.60						
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50		
Current YTD ROY Avg.													1.49	
Current Summer Goal Avg													2.77	

Contact: Steve Weaver

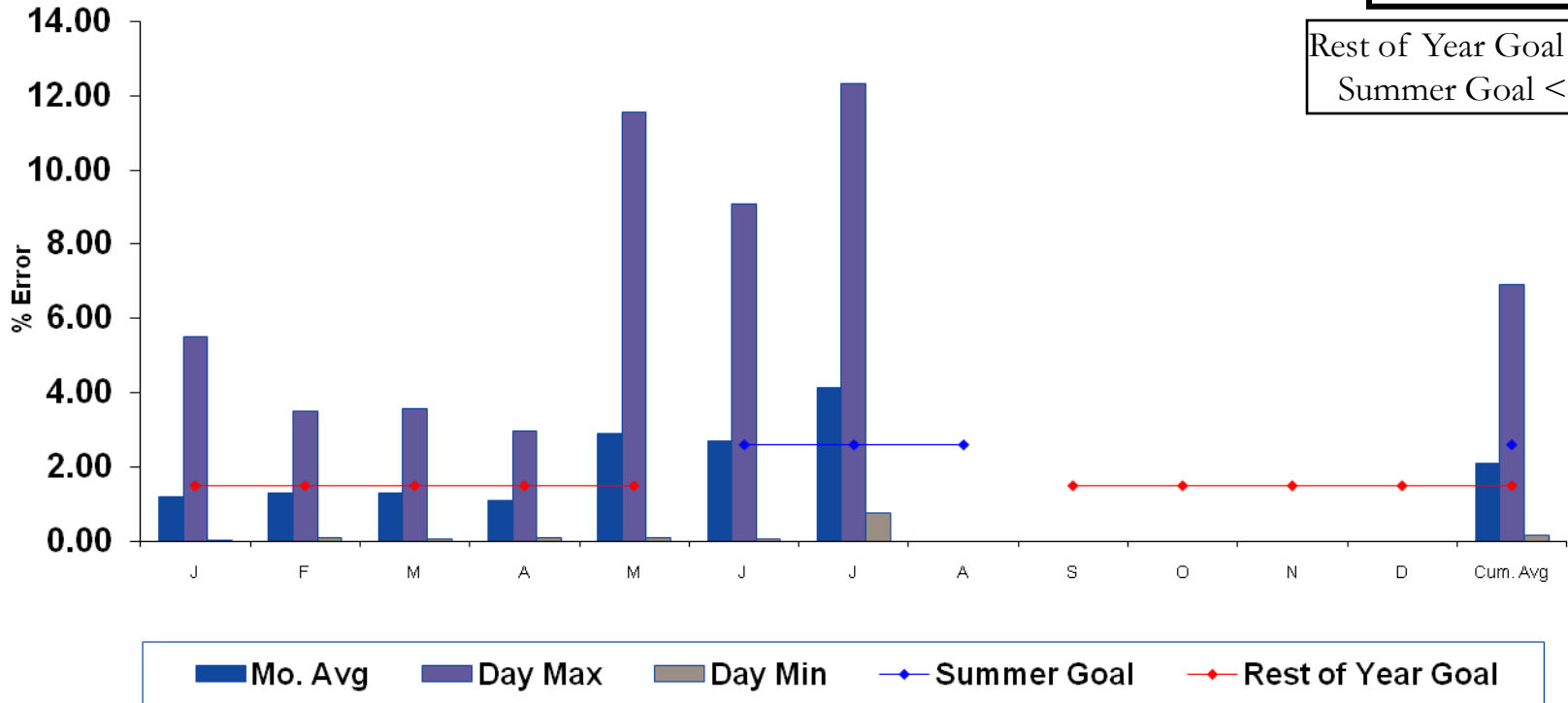
Summer Goal = 2.6% Rest of Year (ROY) Goal = 1.5%  
 Summer consists of June, July and August-

# 2010 System Operations - Load Forecast Accuracy cont.

**Peak Hours**  
**Monthly Average, Daily Maximum and Minimum**  
**Based on forecast published by 1000 on day before Operating Day**

**Dashboard Indicator** 

Rest of Year Goal < 1.5%  
 Summer Goal < 2.6%



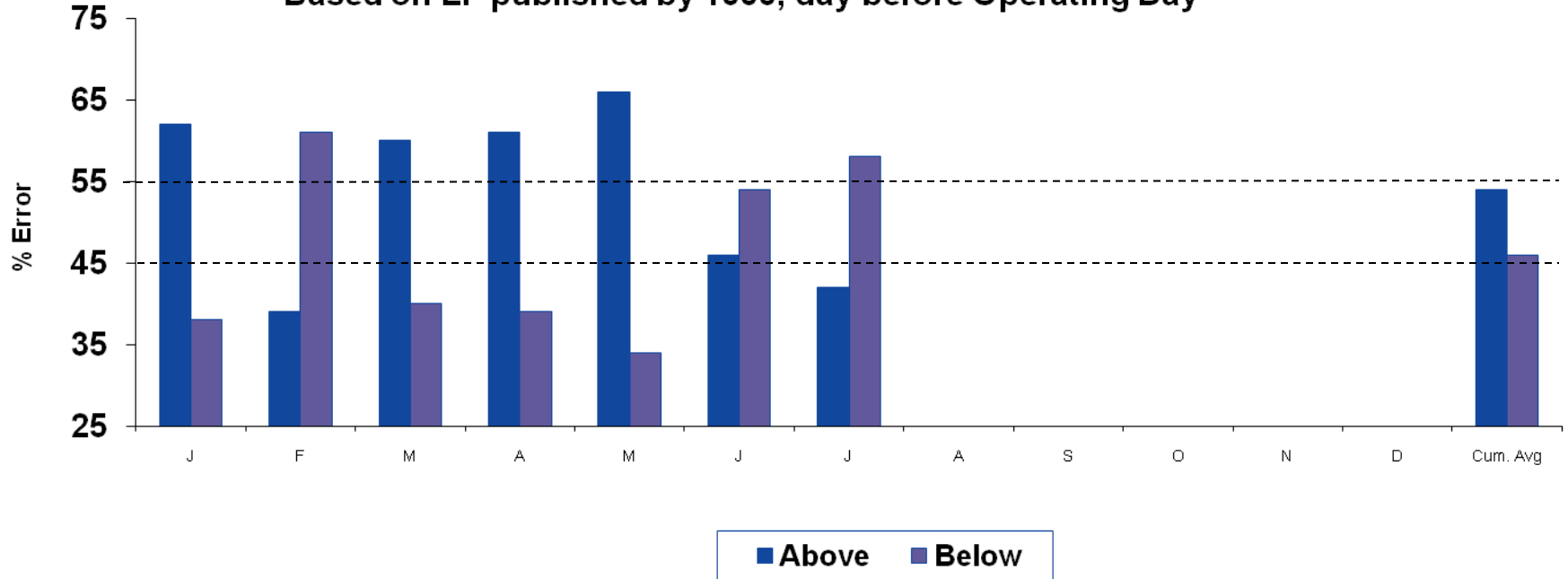
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.20	1.28	1.28	1.10	2.88	2.71	3.82						2.05
Day Max	5.49	3.49	3.55	2.95	11.56	9.07	12.34						6.98
Day Min	0.03	0.07	0.05	0.07	0.08	0.06	0.36						0.10
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Current YTD ROY													1.55
Current Summer Goal Avg													3.27

<b>Contact: Steve Weaver</b>												
Summer Goal = 2.6% Rest of Year(ROY) Goal = 1.5%												
Summer consists of June, July and August.												

# 2010 System Operations - Load Forecast Accuracy

Target = 50%  
Plus/Minus 5%

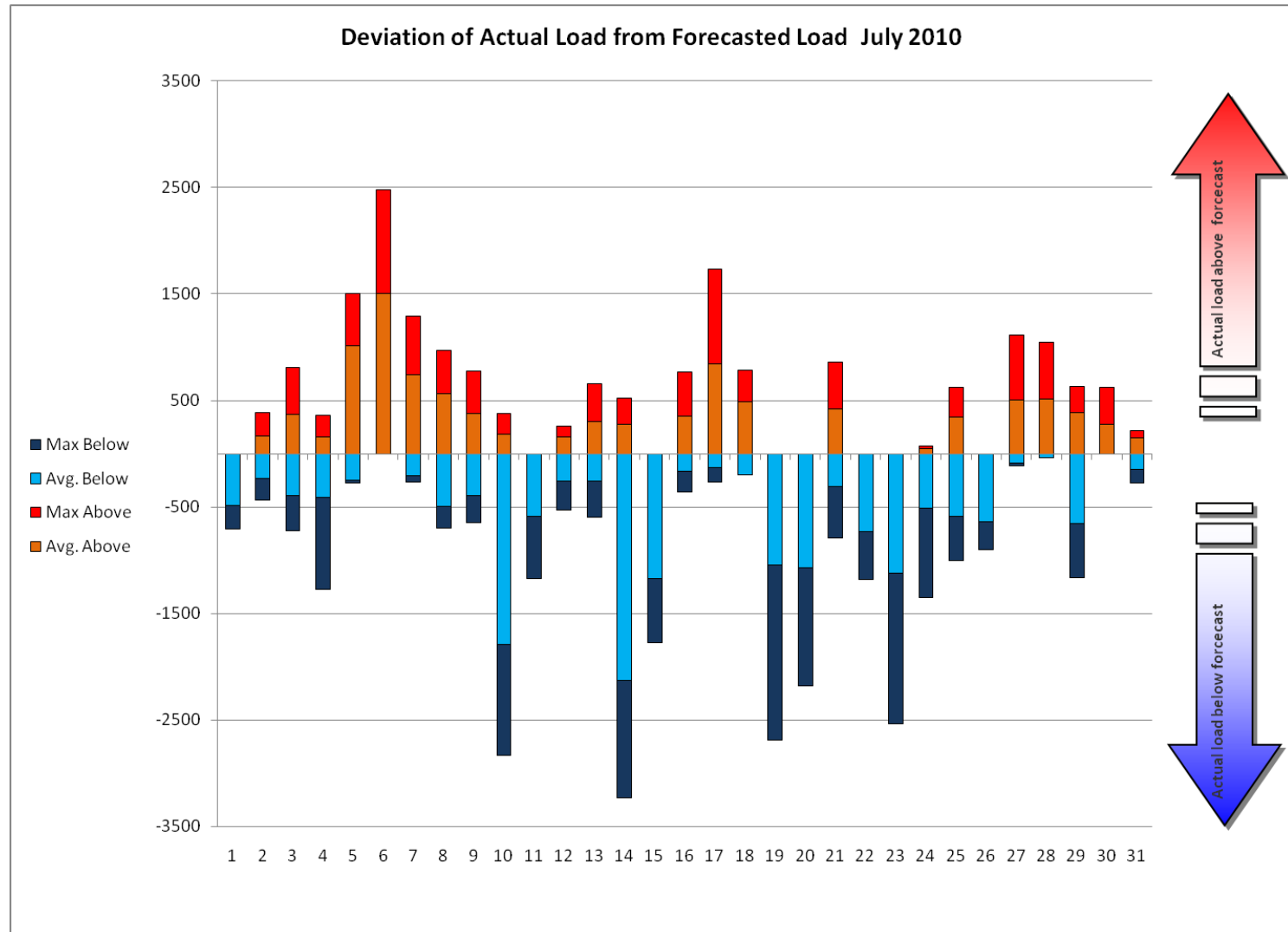
**Percent of Hours Actual Load  
Above vs. Below Forecast**  
Based on LF published by 1000, day before Operating Day



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
<b>Above %</b>	62.0	39.0	60.0	61.0	66.0	46.0	42.0						54.0
<b>Below %</b>	38.0	61.0	40.0	39.0	34.0	54.0	58.0						46.0
<b>Avg Above</b>	178.0	106.0	144.0	147.0	258.0	198	327						193.0
<b>Avg Below</b>	-112.0	-181.0	-118.0	-103.0	-155.0	-314	-533						-211.0
<b>Avg All</b>	74.0	-69.0	38.0	45.0	107.0	-91.0	-166.0						-5.0

Percent of hours during the month that the actual load was above versus below the forecast													
<b>Sponsor:</b>	Michael Taniwha												
<b>Contact:</b>	Steve Weaver												

# 2010 System Operations - Load Forecast Accuracy

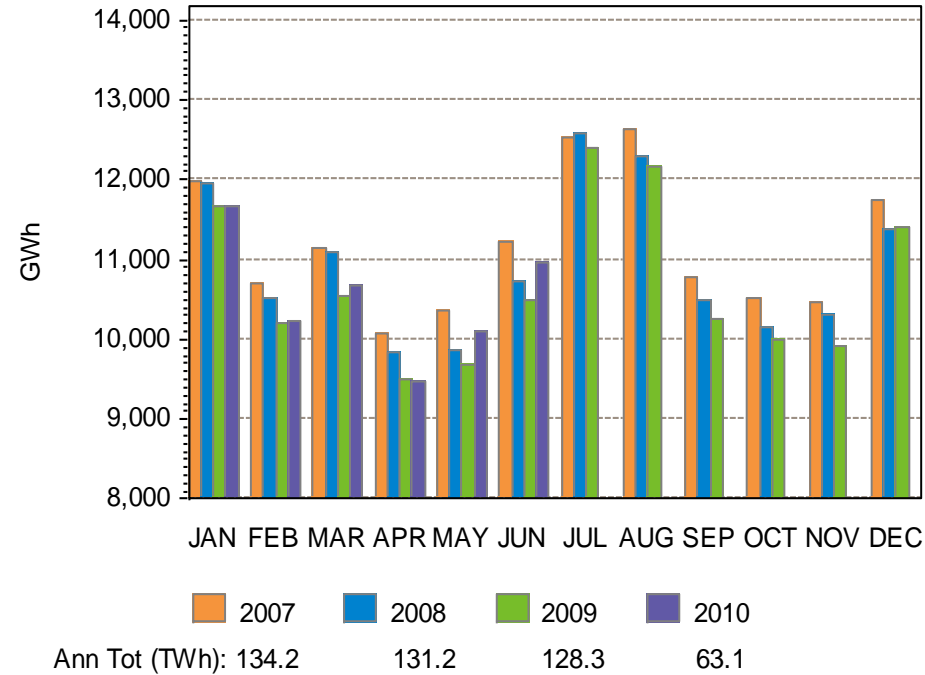
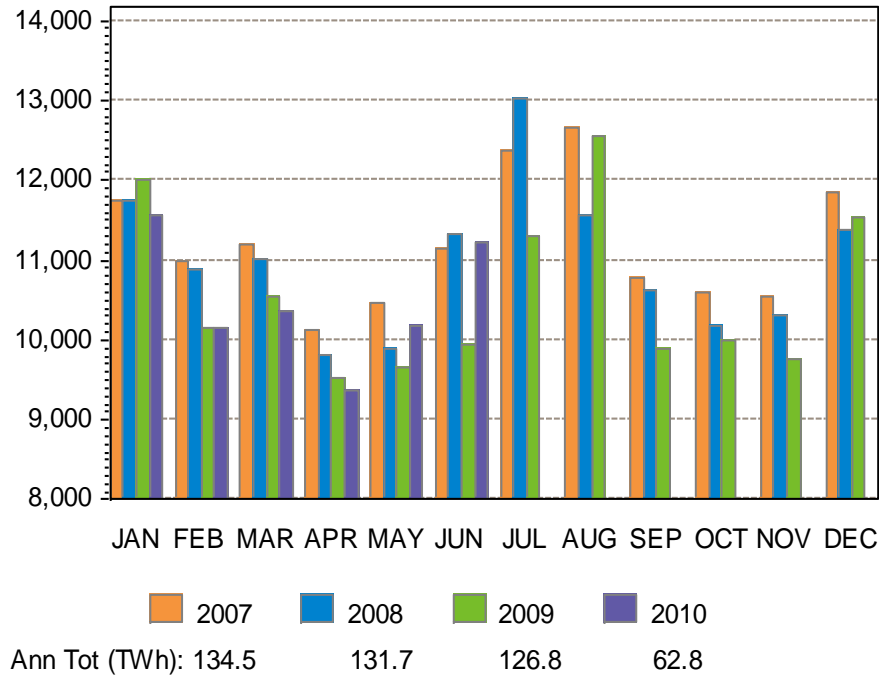


Sponsor	Mike Taniwha
Contact	Steve Weaver

# Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

## Net Energy for Load (NEL)

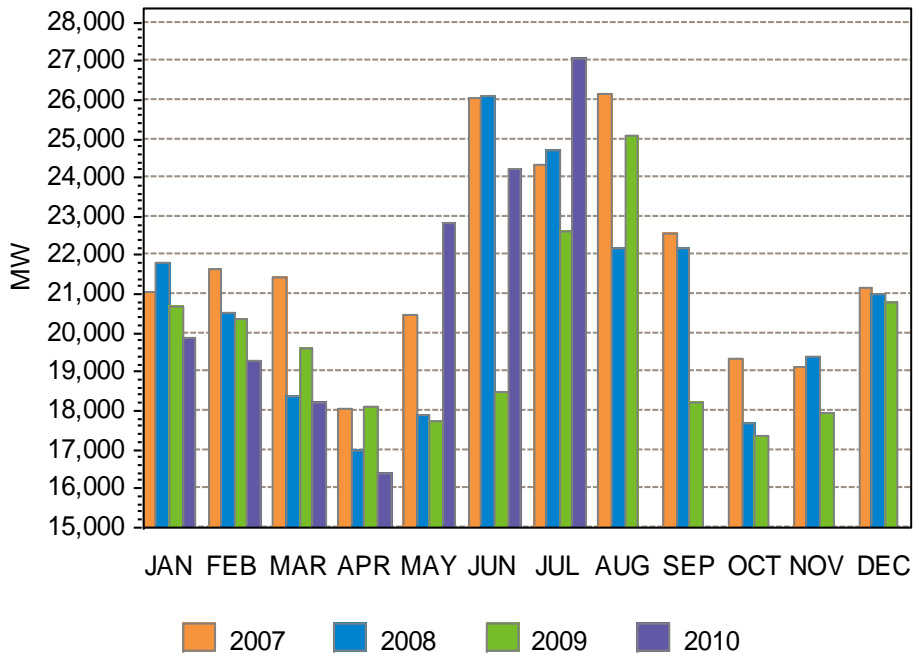
## Weather Normalized NEL



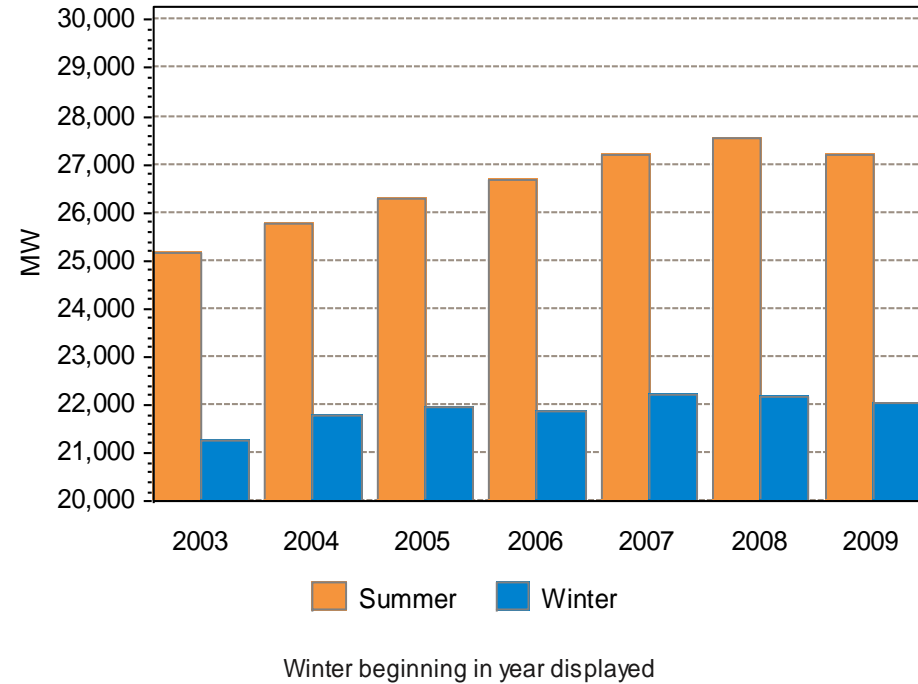
NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Reported on a one month lag.

# Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load

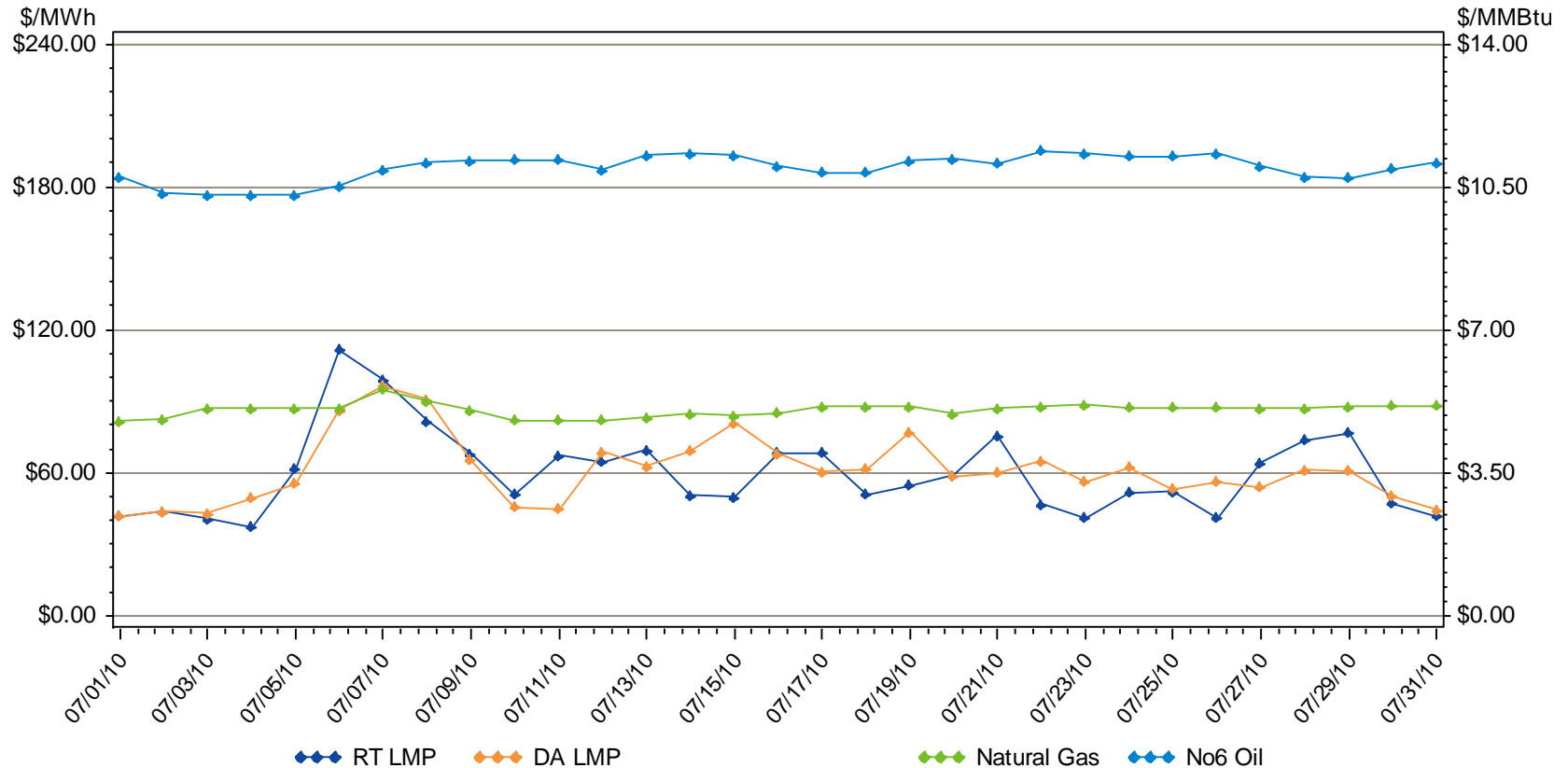


Weather Normalized Seasonal Peaks



# Market Operations

# DA and RT ISO-NE Hub Prices and Input Fuel Prices: July 1-31, 2010



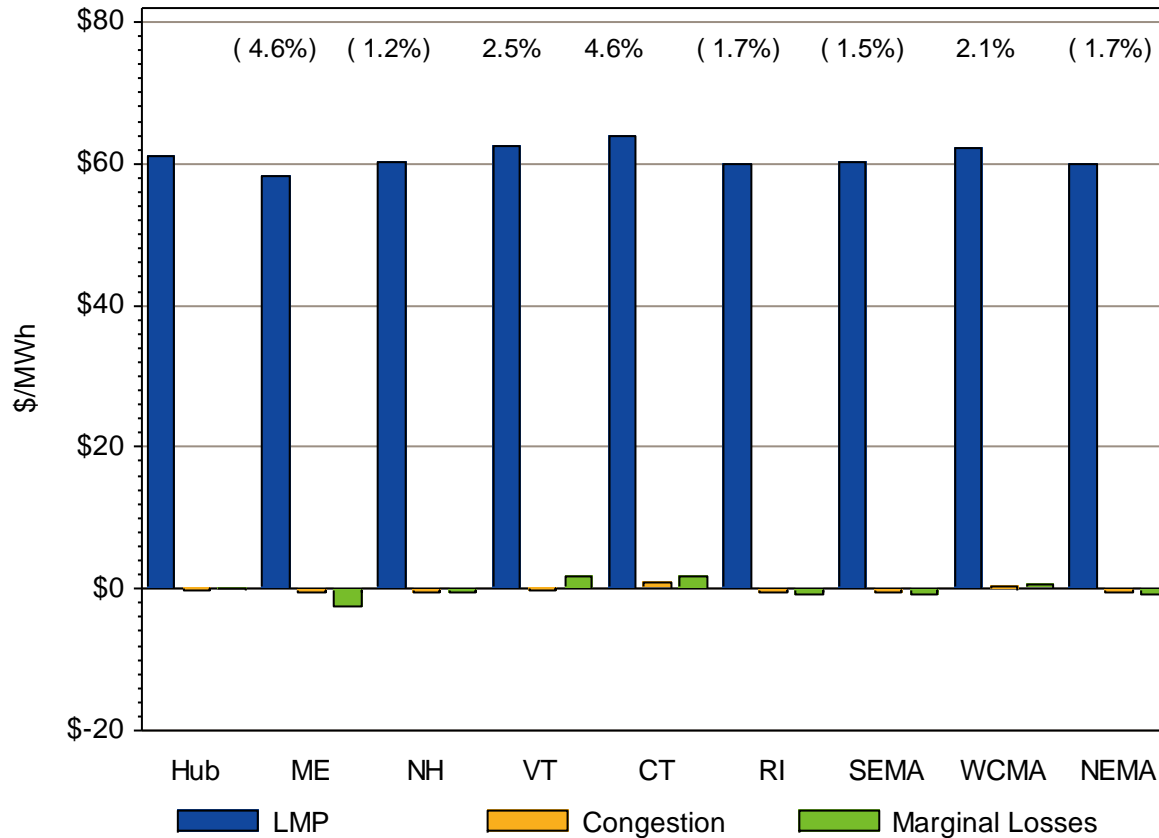
Underlying natural gas data furnished by:



Average price difference over this period (DA-RT): \$1.33  
 Average price difference over this period ABS(DA-RT): \$10.05  
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 17%

Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOE's Energy Information Administration

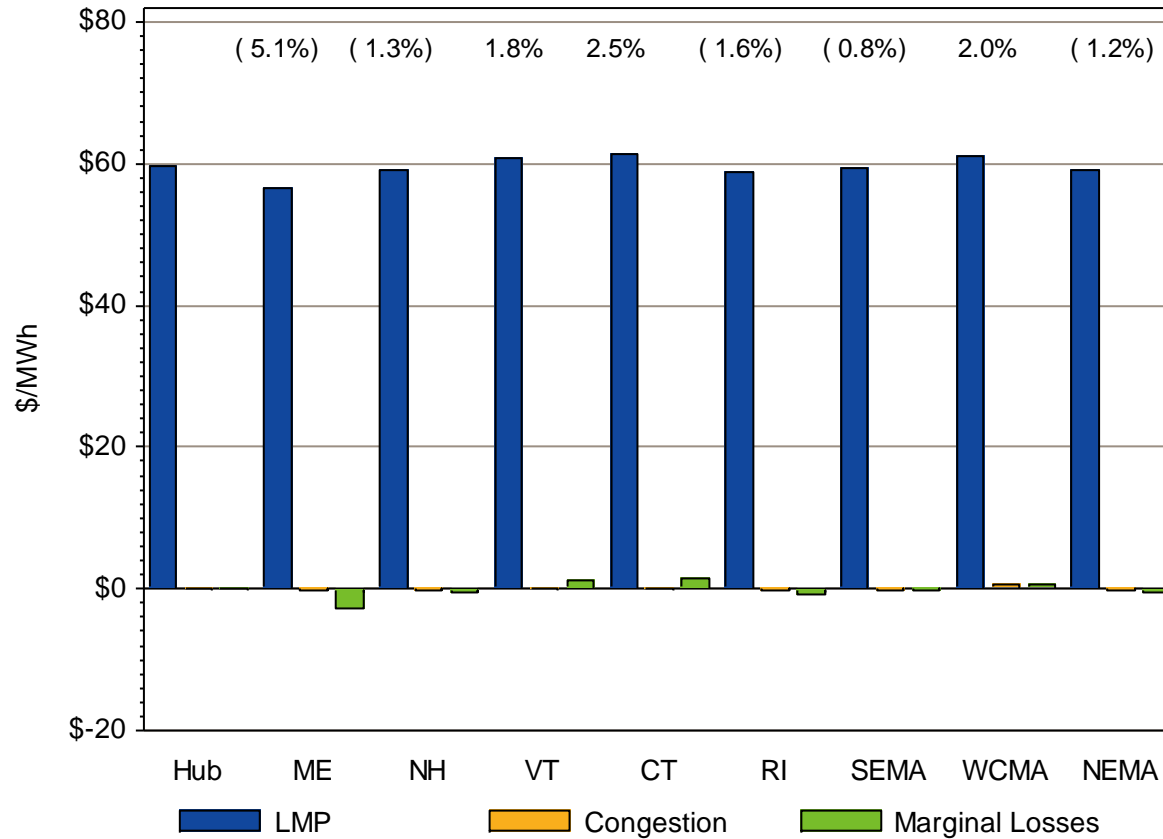
# DA LMPs Average by Zone & Hub – July 2010



ME - Maine  
 NH - New Hampshire  
 VT - Vermont  
 CT - Connecticut

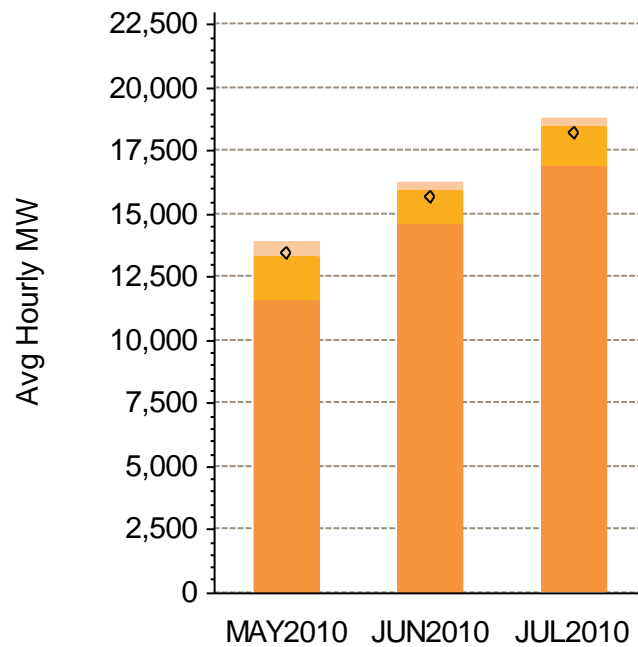
RI - Rhode Island  
 SEMA - Southeastern Massachusetts  
 WCMA - Western/Central Massachusetts  
 NEMA - Northeastern Massachusetts

# RT LMPs Average by Zone & Hub – July 2010



# Components of Cleared DA Supply and Demand – Last Three Months

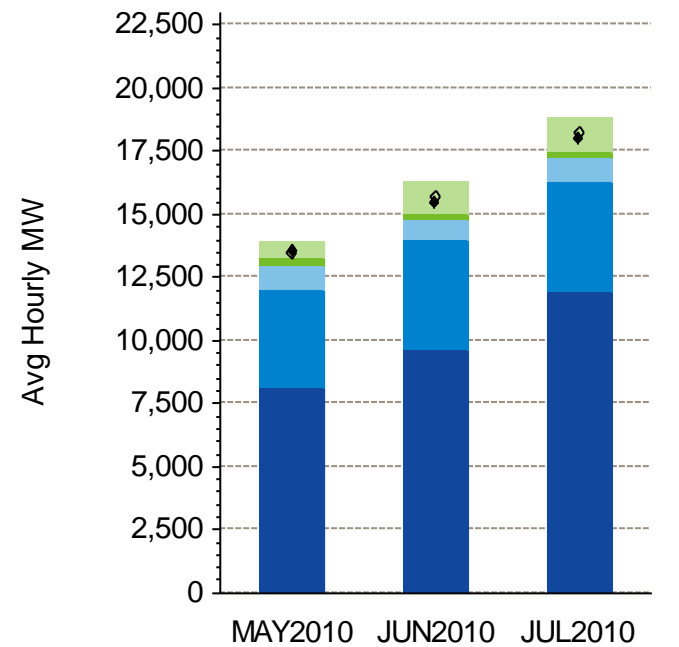
## Supply



■ Gen      ■ Incs  
■ Imports      ◇ DA Fcst Load

Gen – Generation  
 Incs – Increment Offers  
 DA Fcst Load – Day-Ahead Forecast Load

## Demand

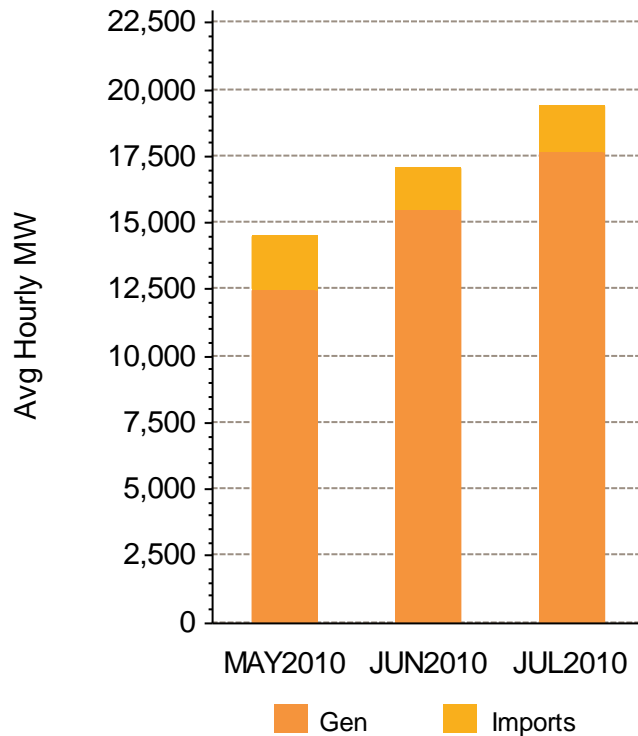


■ Fixed Dem      ■ PrSens Dem      ■ Decs  
■ Losses      ■ Exports      ◇ Act Load

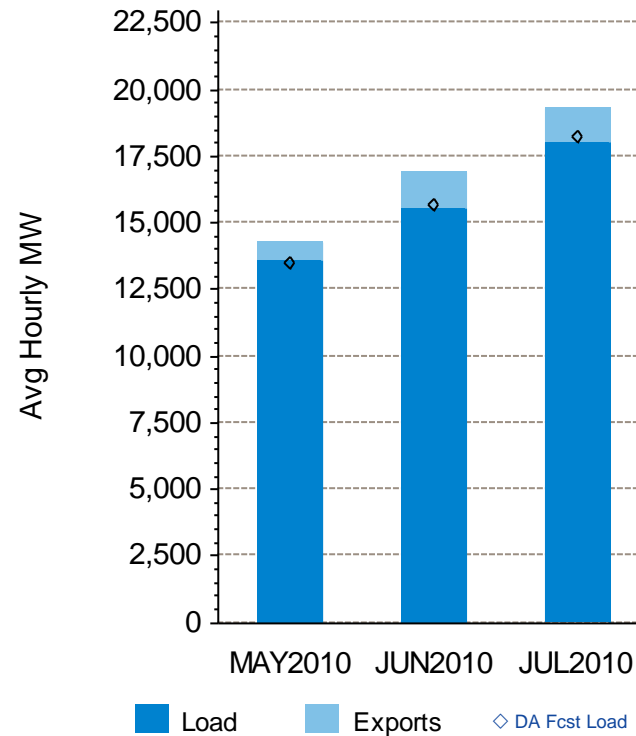
Fixed Dem – Fixed Demand  
 PrSens Dem – Price Sensitive Demand  
 Decs – Decrement Bids  
 Act Load – Actual Load

# Components of RT Supply and Demand – Last Three Months

## Supply

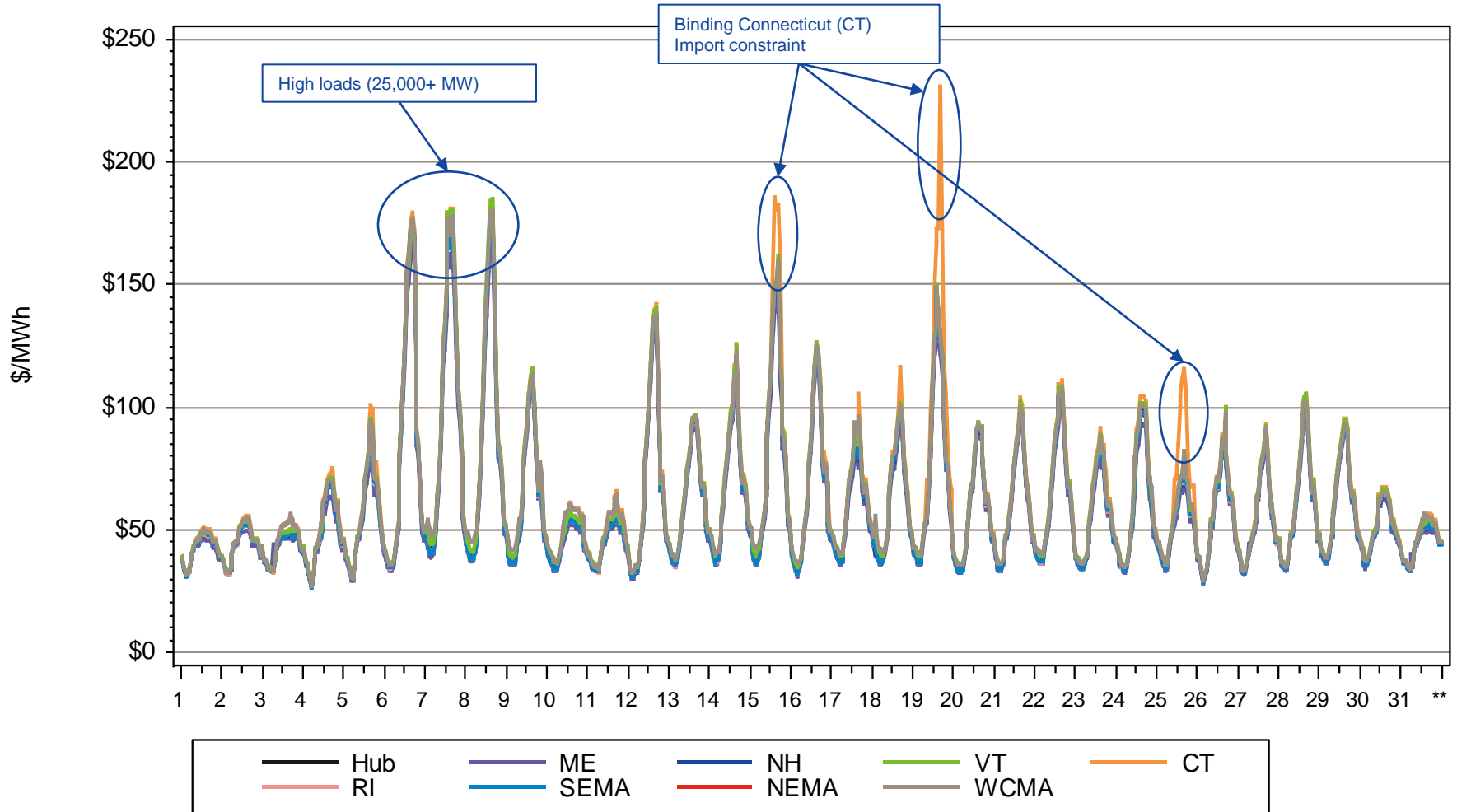


## Demand

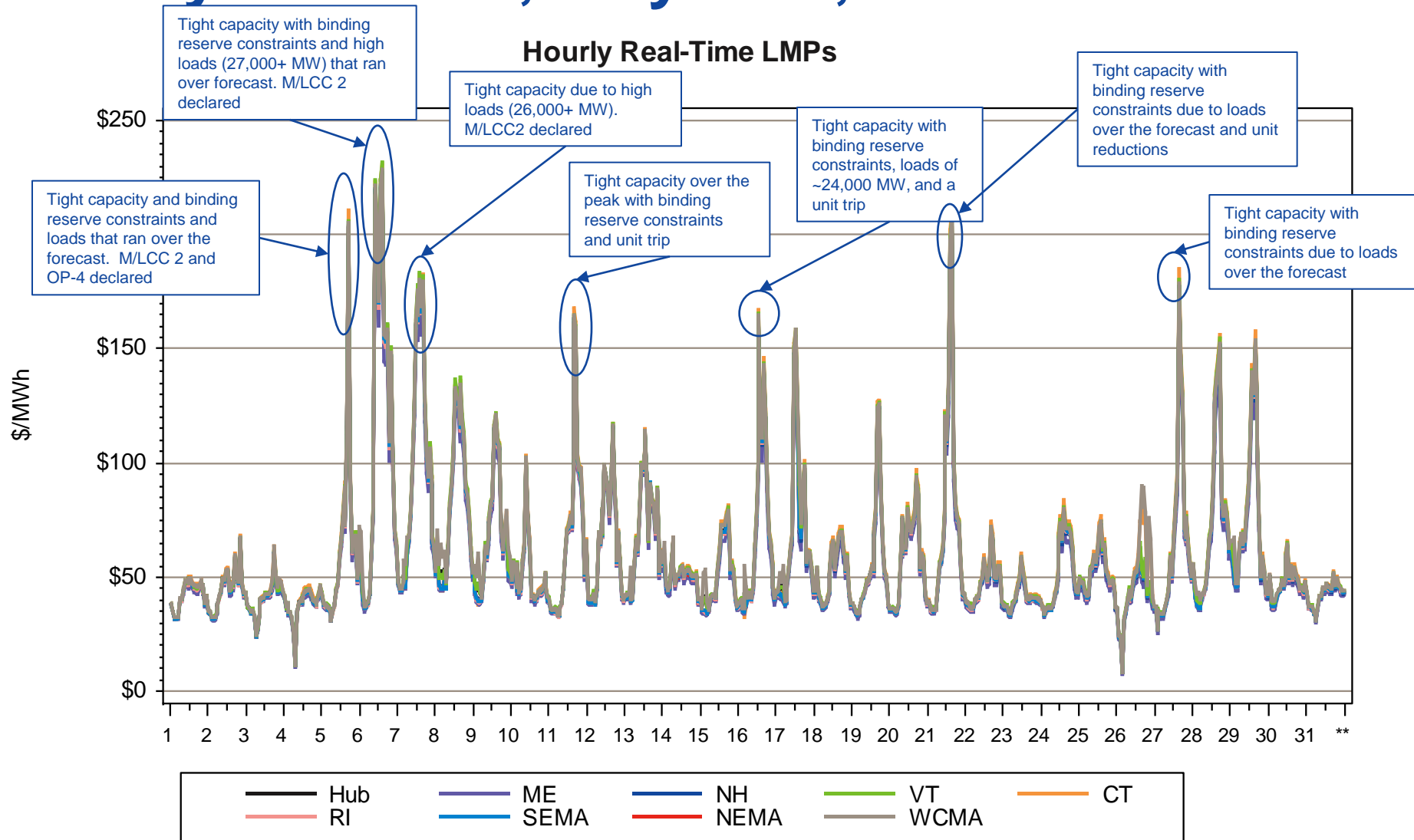


# Hourly DA LMPs, July 1-31, 2010

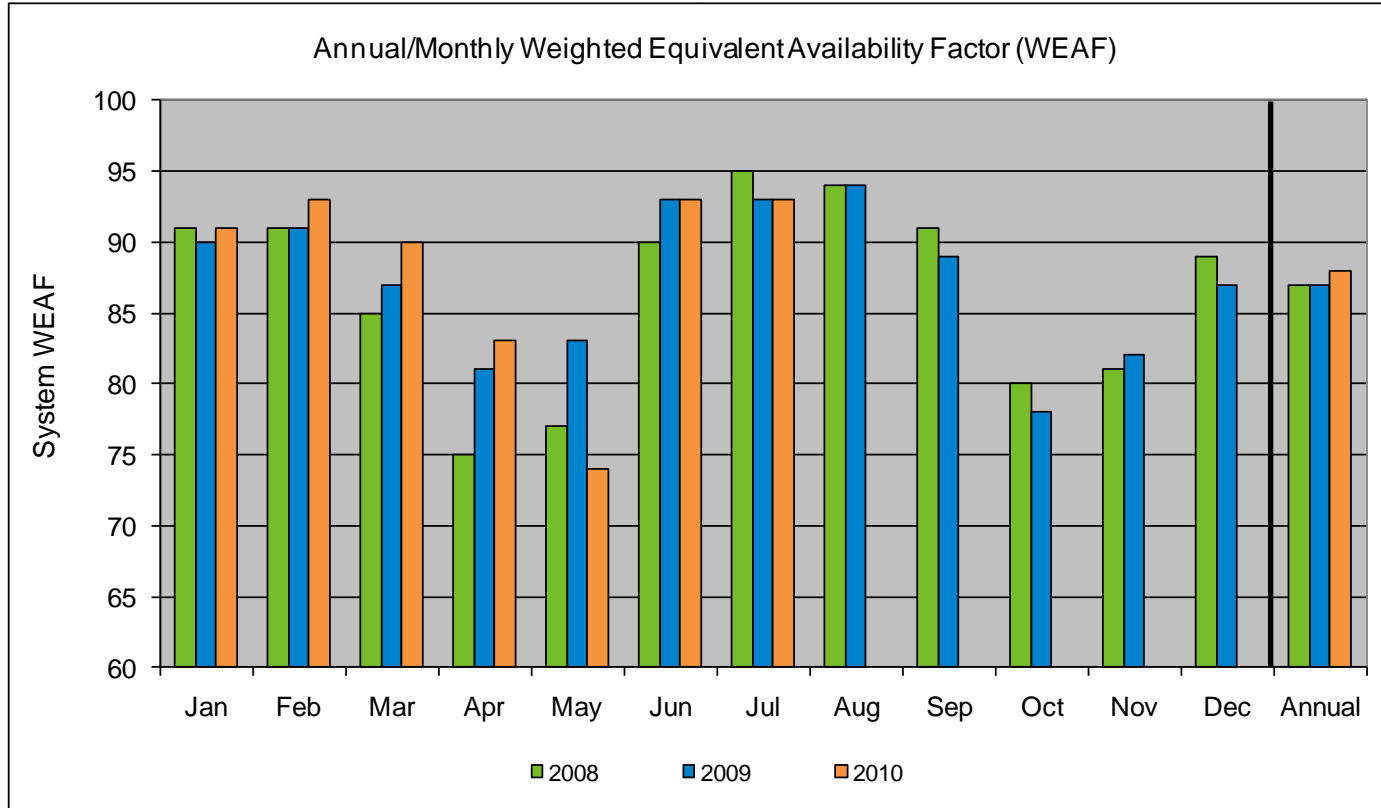
## Hourly Day-Ahead LMPs



# Hourly RT LMPs, July 1-31, 2010



# System Unit Availability



Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	YTD	
91	93	90	83	74	93	93						88	2010
												87	2009
												87	2008
												90	2007

**DEFINITION:** System Weighted Average Availability Factor of New England Generating Units  
**FORMULA:** (1 - System Forced Outage Rate)\*(1 - System Scheduled Outage Rate)  
**Data current as of 07/30/2010**  
**Sponsor:** Steve Rourke  
**Contact:** Susan Haas

# Back-up Detail

# Load Response

# Net Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2010

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	165.71	17.59	19.83	0.00	203.13
NH	27.69	21.57	32.42	0.00	81.68
VT	23.35	10.32	41.74	0.00	75.41
CT	219.48	255.13	56.82	108.53	639.97
RI	27.76	39.40	34.46	0.00	101.62
SEMA	39.34	35.71	60.85	0.00	135.90
WCMA	81.05	56.62	56.22	9.48	203.37
NEMA	67.61	66.63	97.73	0.00	231.97
<b>Total</b>	<b>669.41</b>	<b>522.39</b>	<b>406.24</b>	<b>118.01</b>	<b>1,716.05</b>

\* Real-Time Demand Response

\*\* Real-Time Demand Response with Emergency Generation

NOTE: Net CSO values exclude T&D loss factor (8%) and reserve margin gross-up (14.3%)

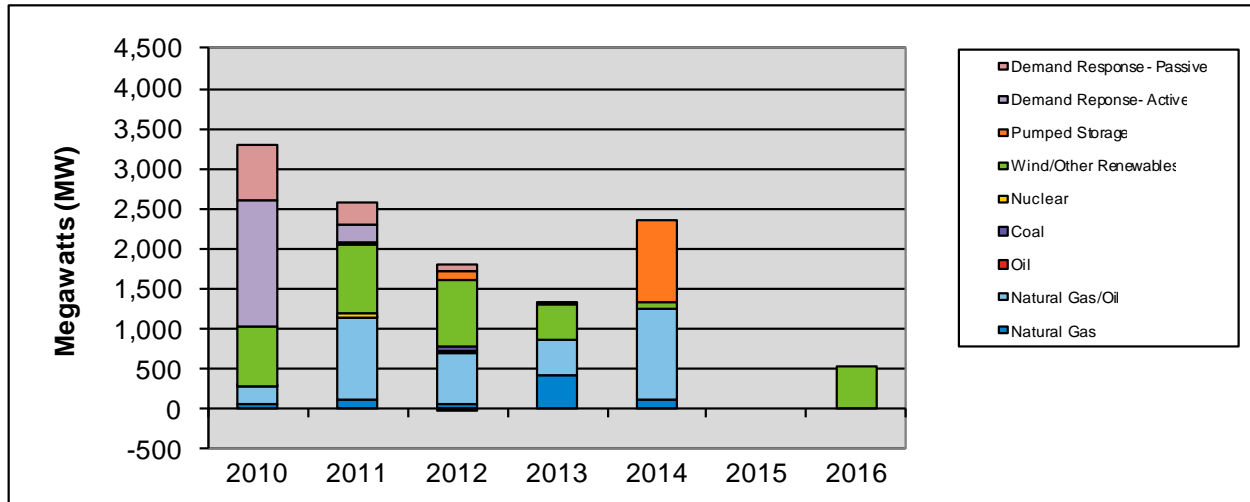
# New Generation

# New Generation Update

- One 33 MW new generation project and one 12 MW generator upgrade project has applied for interconnection study since the last update
  - The new generation project is a biomass facility while the upgrade is being done on a natural gas facility
  - Projected in-service dates are in 2013 and 2011 respectively
- Four projects, totaling approximately 250 MW went commercial, while five projects, totaling approximately 500 MW withdrew from the queue
- In total, 89 generation projects are currently being tracked by the ISO, totaling approximately 8,800 MW\*

\* In the case where a project involves the retirement of a companion unit, only the net MW increase is reported

# Actual and Projected Annual Capacity Additions By Supply Fuel Type and Demand Resource Type

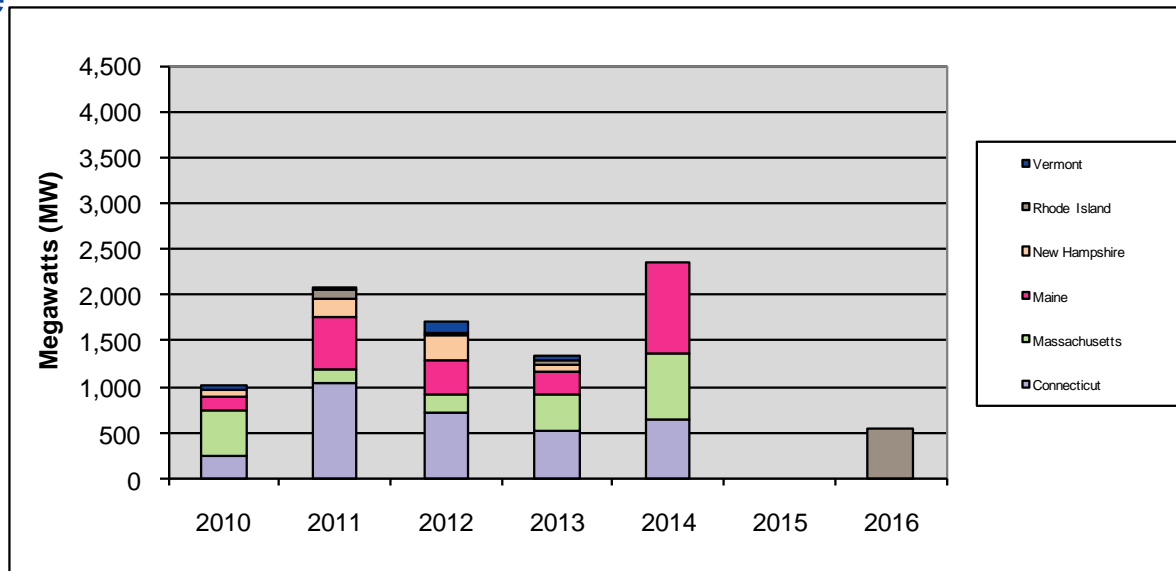


	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	0	0	0	0	1,073	9.0
Demand Response - Active	1,579	221	-6	0	0	0	0	1,794	15.1
Pumped Storage	0	25	111	25	1,025	0	0	1,186	10.0
Wind & Other Renewables	726	869	839	460	91	0	536	3,521	29.5
Nuclear	0	45	0	0	0	0	0	45	0.4
Coal	17	0	36	0	0	0	0	53	0.4
Oil	0	13	30	0	0	0	0	43	0.4
Natural Gas/Oil	218	1,018	640	444	1,131	0	0	3,451	29.0
Natural Gas	54	120	60	411	107	0	0	752	6.3
<b>Totals</b>	<b>3,294</b>	<b>2,589</b>	<b>1,805</b>	<b>1,340</b>	<b>2,354</b>	<b>0</b>	<b>536</b>	<b>11,918</b>	<b>100.0</b>

- 2010 values include the 292 MW of generation that has gone commercial in 2010
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

# Actual and Projected Annual Generator Capacity Additions

## By State



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
<b>Vermont</b>	61	25	129	64	0	0	0	279	3.1
<b>Rhode Island</b>	0	101	34	29	0	0	536	700	7.7
<b>New Hampshire</b>	59	218	267	86	0	0	0	630	7.0
<b>Maine</b>	162	550	377	251	1,000	0	0	2,340	25.9
<b>Massachusetts</b>	492	153	183	405	719	0	0	1,952	21.6
<b>Connecticut</b>	241	1,043	726	505	635	0	0	3,150	34.8
<b>Totals</b>	<b>1,015</b>	<b>2,090</b>	<b>1,716</b>	<b>1,340</b>	<b>2,354</b>	<b>0</b>	<b>536</b>	<b>9,051</b>	<b>100.0</b>

- 2010 values include the 292 MW of generation that has gone commercial in 2010

# New Generation Projection By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	14	462	1	38	13	424
Coal	1	36	0	0	1	36
Hydro	8	1,219	0	24	8	1,195
Landfill Gas	1	34	0	0	1	34
Natural Gas	9	721	0	0	9	721
Natural Gas/Oil	13	3,233	3	943	10	2,290
Nuclear Uprates	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Solar	0	0	0	0	0	0
Wind	33	2,966	4	180	29	2,786
<b>Total</b>	<b>83</b>	<b>8,759</b>	<b>8</b>	<b>1,185</b>	<b>75</b>	<b>7,574</b>

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

# New Generation Projection

## By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	19	586	1	38	18	548
Intermediate	17	3,349	1	644	16	2,705
Peaker	14	1,858	2	323	12	1,535
Wind Turbine	33	2,966	4	180	29	2,786
<b>Total</b>	<b>83</b>	<b>8,759</b>	<b>8</b>	<b>1,185</b>	<b>75</b>	<b>7,574</b>

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

# New Generation Projection By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	14	462	14	462	0	0	0	0	0	0
Coal	1	36	1	36	0	0	0	0	0	0
Hydro	8	1,219	0	0	5	33	3	1,186	0	0
Landfill Gas	1	34	1	34	0	0	0	0	0	0
Natural Gas	9	721	1	9	4	679	4	33	0	0
Natural Gas/Oil	13	3,233	0	0	8	2,637	5	596	0	0
Nuclear Uprates	2	45	2	45	0	0	0	0	0	0
Oil	2	43	0	0	0	0	2	43	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Wind	33	2,966	0	0	0	0	0	0	33	2,966
<b>Total</b>	<b>83</b>	<b>8,759</b>	<b>19</b>	<b>586</b>	<b>17</b>	<b>3,349</b>	<b>14</b>	<b>1,858</b>	<b>33</b>	<b>2,966</b>

# Capacity Supply Obligations (CSO) FCA 1

Resource Type	Resource Type	FCA 1	Proration		ARA 2		**Delisted MW Released		Annual Bilateral		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	1,850.074	1,818.402	-31.672	1,817.152	-1.250	1,817.152	0.000	1,515.593	-301.559	1,498.671	-16.922
	Passive Demand	703.488	689.729	-13.759	666.729	-23.000	666.729	0.000	654.078	-12.651	654.078	0.000
Demand Total		2,553.562	2,508.131	-45.431	2,483.881	-24.250	2,483.881	0.000	2,169.671	-314.210	2,152.749	-16.922
Generator Total		30,864.929	29,710.469	-1,154.460	29,814.719	104.250	29,646.719	-168.000	30,406.108	759.389	30,456.525	50.417
Import Total		933.583	898.542	-35.041	818.542	-80.000	818.542	0.000	373.363	-445.179	339.868	-33.495
ISO New England Participation		N/A	N/A	N/A	0.000	N/A	N/A	N/A	N/A	N/A	-242.442	N/A
Grand Total		34,352.074	33,117.142	1,234.932	33,117.142	0.000	32,949.142	-168.000	32,949.142	0.000	32,706.700	0.000

\* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

\*\* Some Capacity that was previously held for reliability was released

# Reliability Costs

# Net Commitment Period Compensation (NCPC) Operating Costs

# What are Daily NCPC Payments?

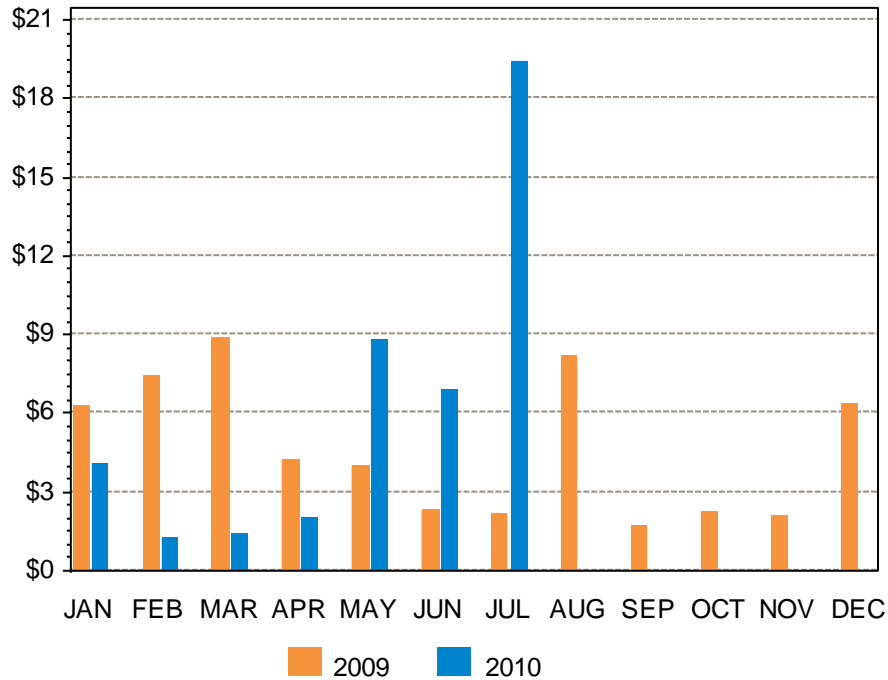
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

# Definitions

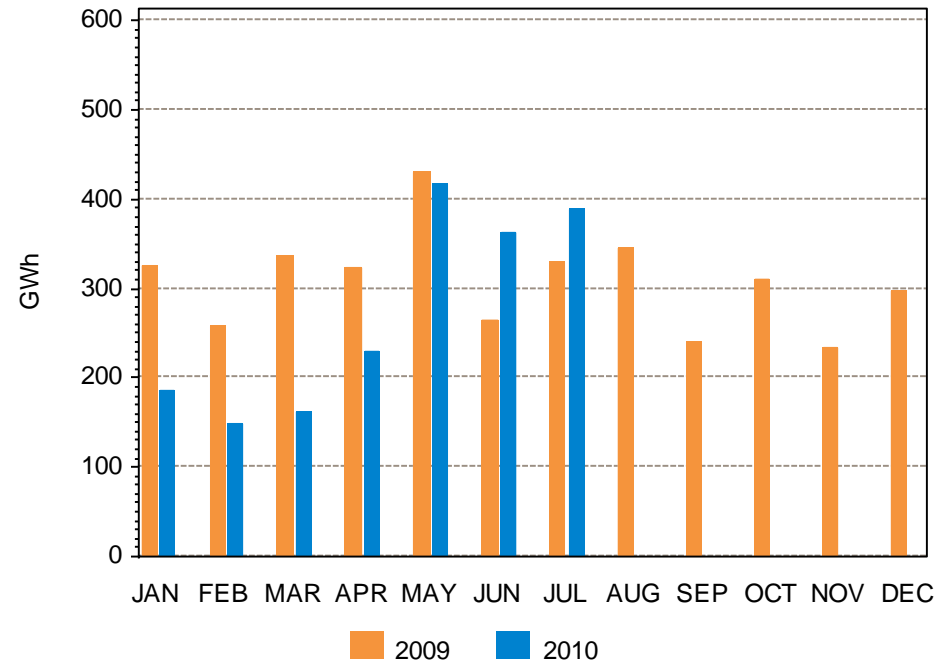
<b>Voltage NCPC Payments</b>	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
<b>Distribution NCPC Payments</b>	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
<b>1<sup>st</sup> Contingency NCPC Payments</b>	Reliability costs paid to eligible resources that are not providing 2 <sup>nd</sup> Contingency, Voltage, or Distribution requirements. These resources may have been providing first contingency coverage (system-wide or locally)
<b>2<sup>nd</sup> Contingency NCPC Payments</b>	Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on 2 <sup>nd</sup> Contingency protocols
<b>Delisted Units</b>	Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market

# Year-Over-Year Total NCPC Dollars and Energy

Dollars



Energy

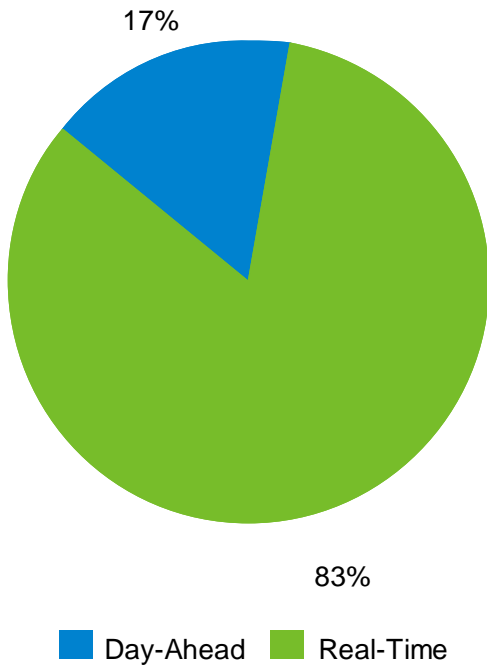


**Note:**

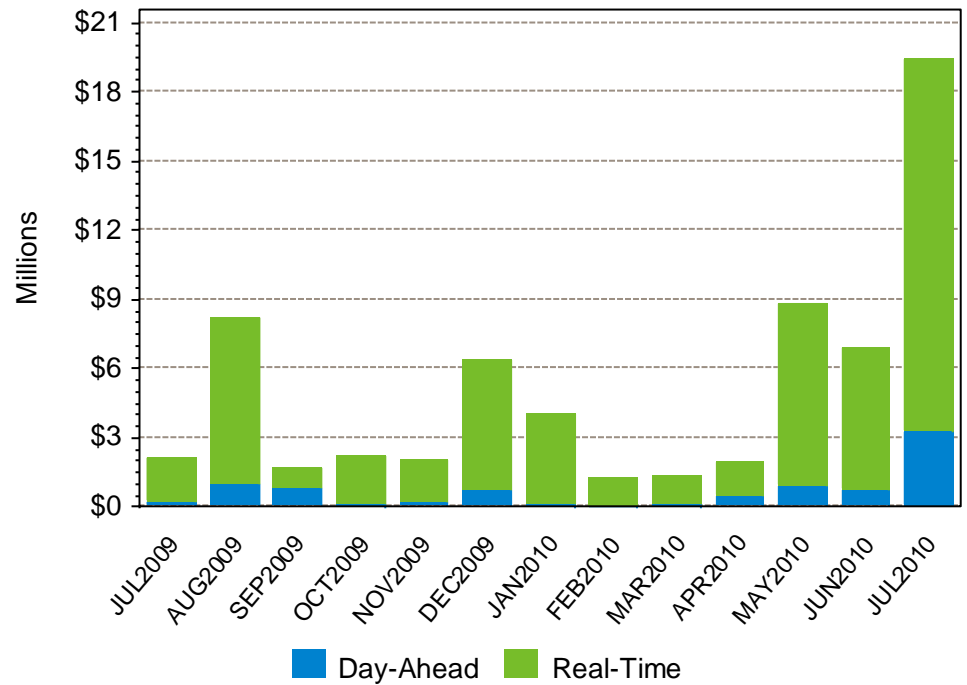
- Overall Reliability Cost MWh includes out of merit DA and RT 1<sup>st</sup> Contingency, 2<sup>nd</sup> Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

# DA and RT NCPC Payments

JUL-10 Total = 19.41 M

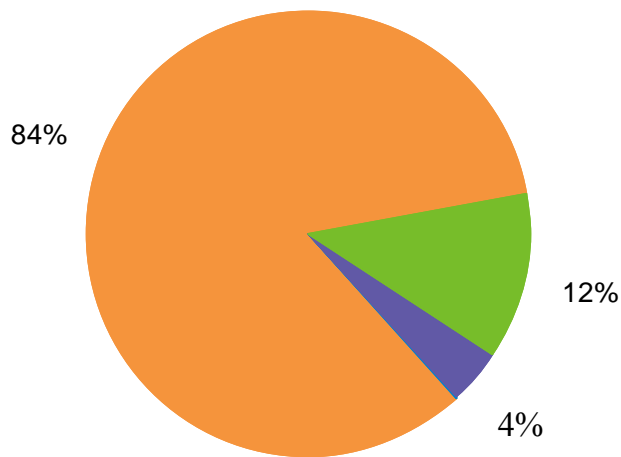


Last 13 Months

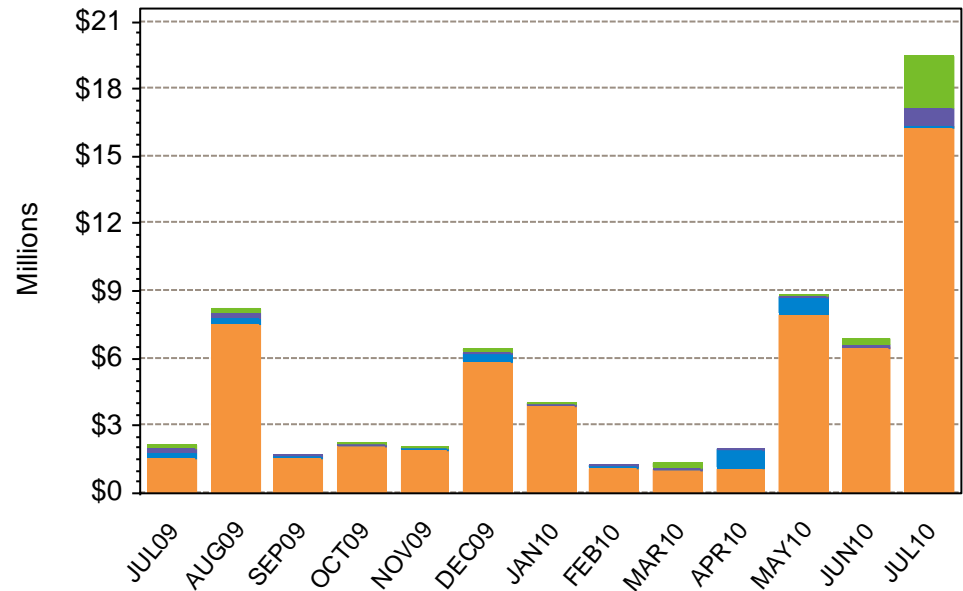


# NCPC Payments by Type

JUL-10 Total = 19.41 M



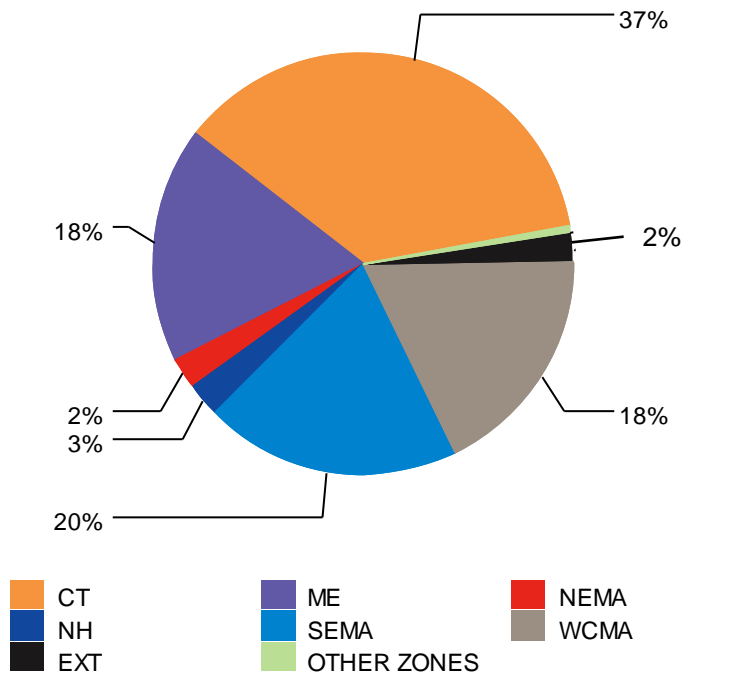
Last 13 Months



1<sup>st</sup> C – First Contingency  
 2<sup>nd</sup> C – Second Contingency  
 Distrib – Distribution  
 Voltage – Voltage Support

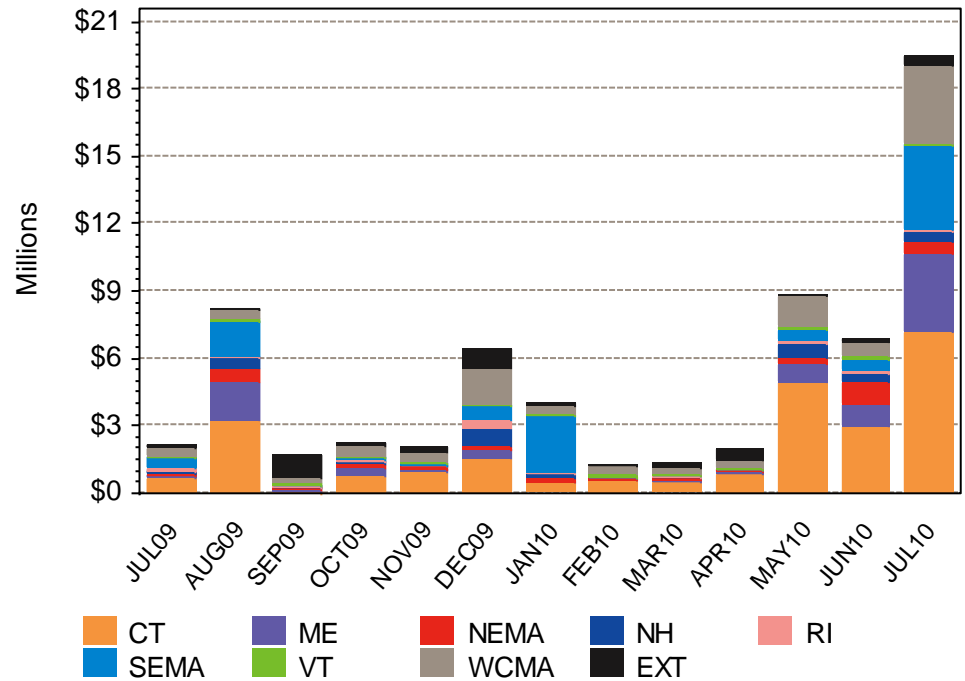
# NCPC Payments by Location

JUL-10 Total = 19.41 M



CT – Connecticut Region  
 ME – Maine Region  
 NH – New Hampshire Region  
 RI – Rhode Island Region

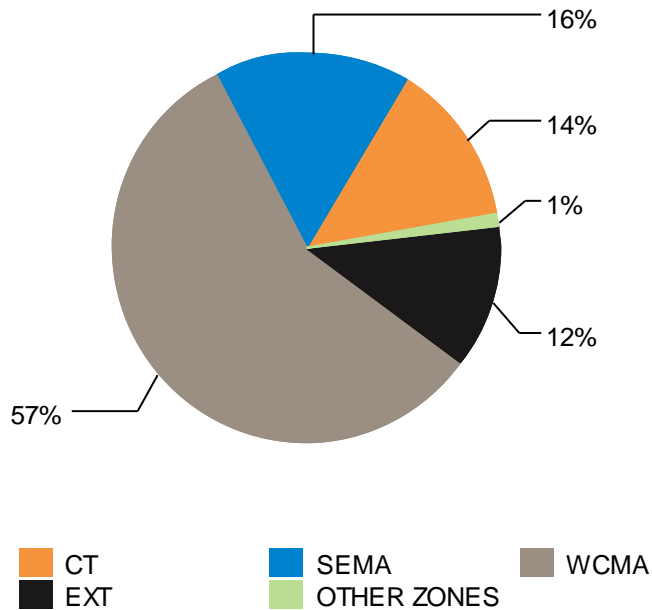
Last 13 Months



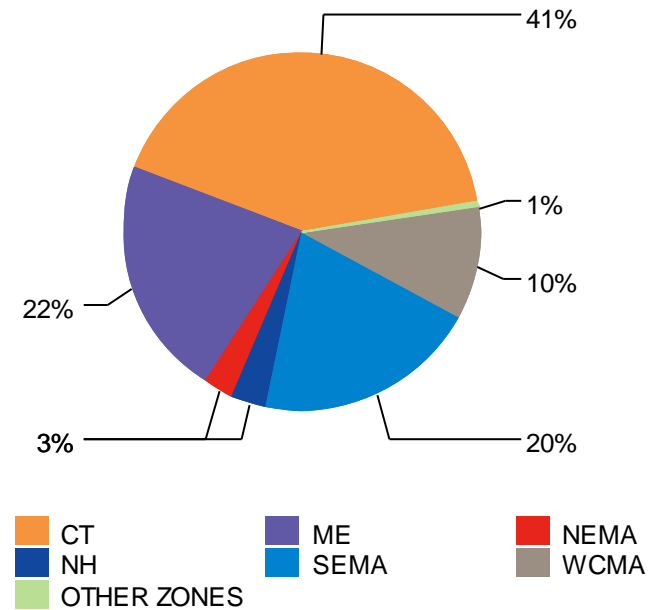
VT – Vermont Region  
 SEMA – Southeast Massachusetts Region  
 WCMA – Western/Central Massachusetts Region  
 NEMA – Northeast Massachusetts Region  
 EXT – External Locations

# DA and RT NCPC Payments by Location

JUL-10 Day-Ahead Total = \$3.28 M

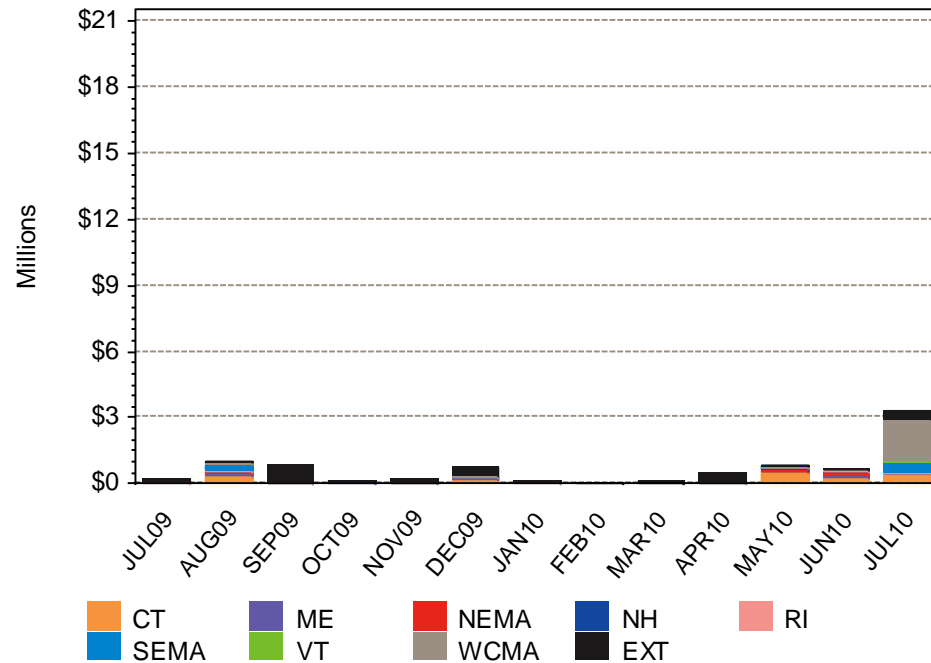


JUL-10 Real-Time Total = 16.13 M

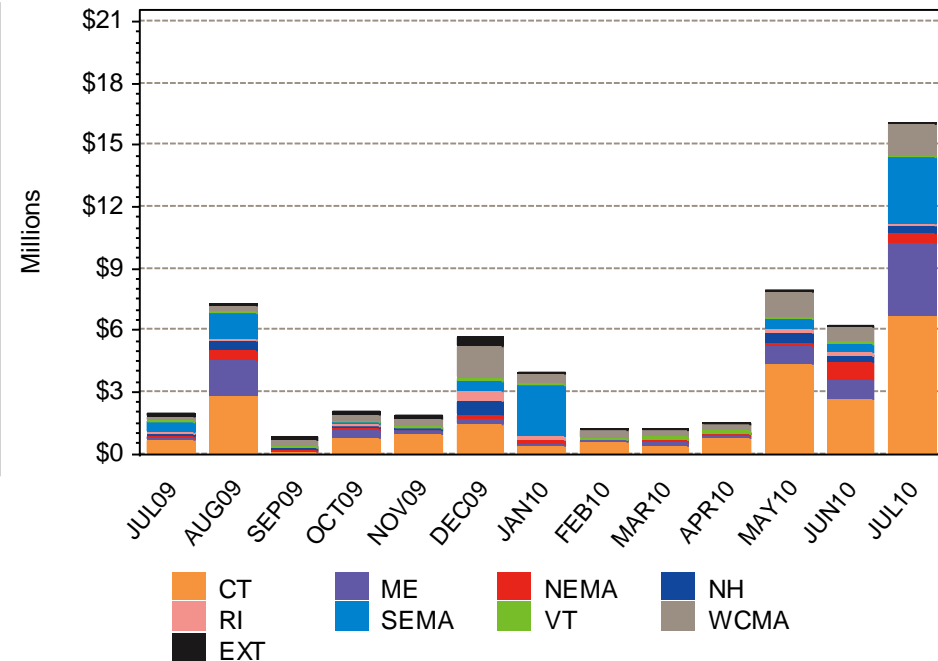


# DA and RT NCPC Payments by Location, Last 13 Months

## Day-Ahead, Last 13 Months

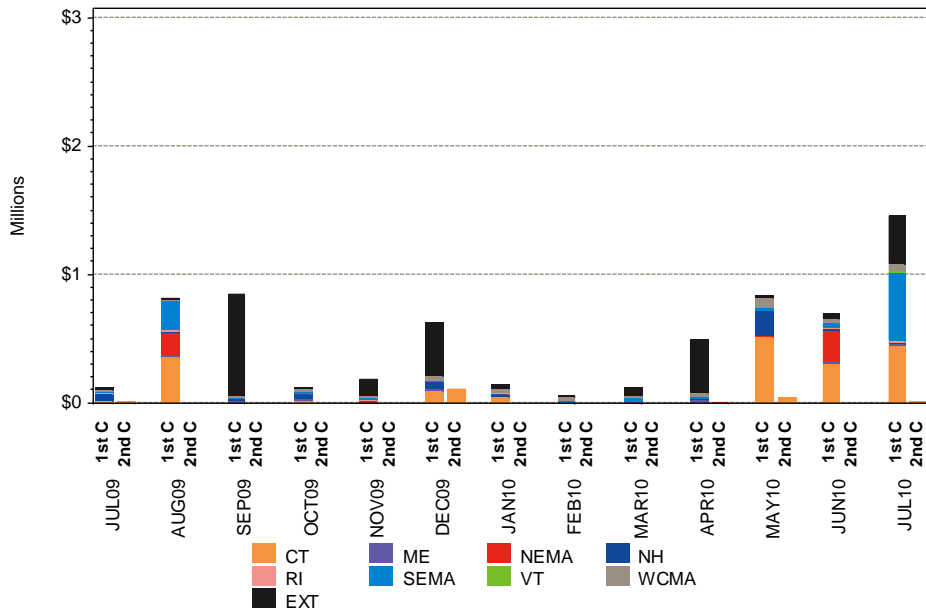


## Real-Time, Last 13 Months

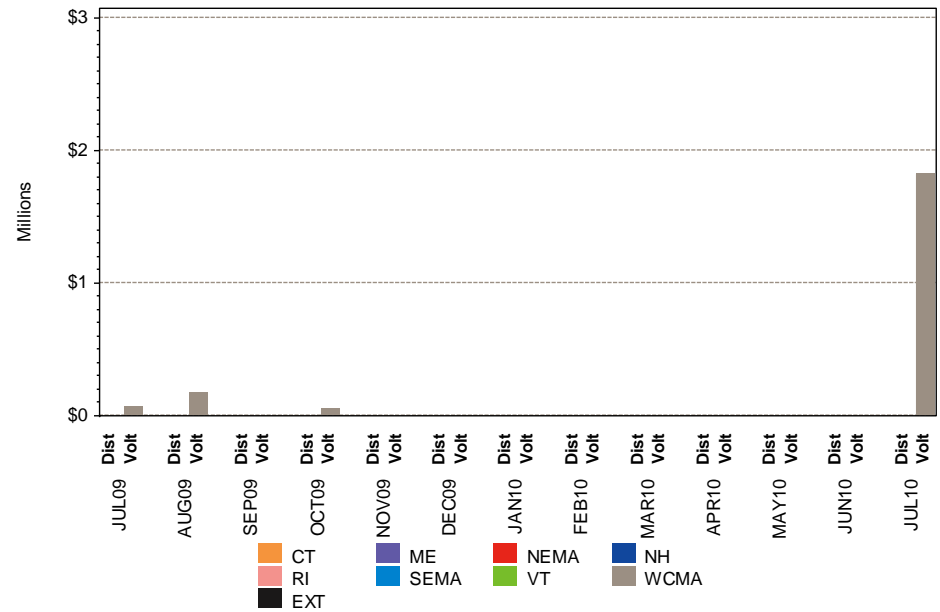


# DA NCPC Payments by Type and Location

## First and Second Contingency Payments

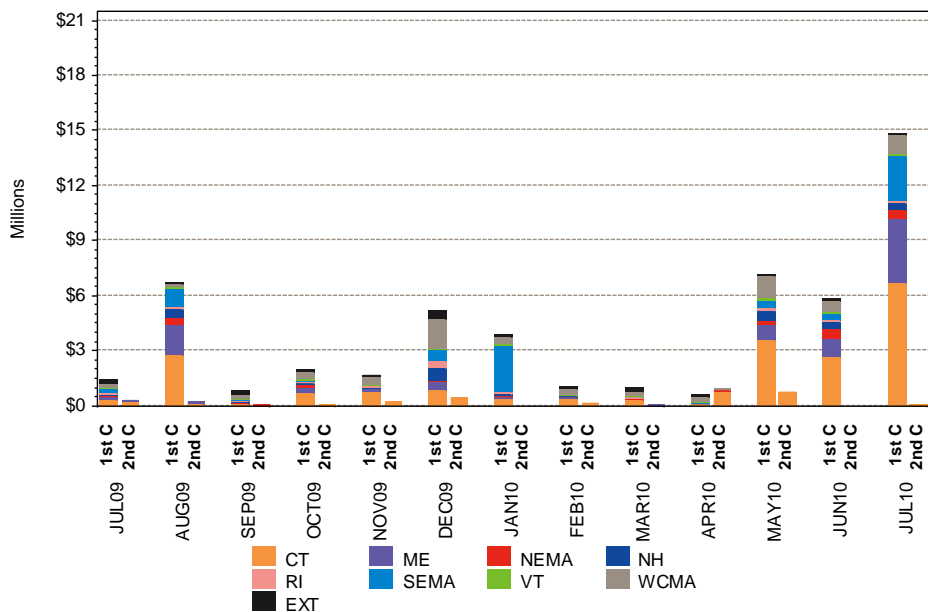


## Voltage and Distribution Payments

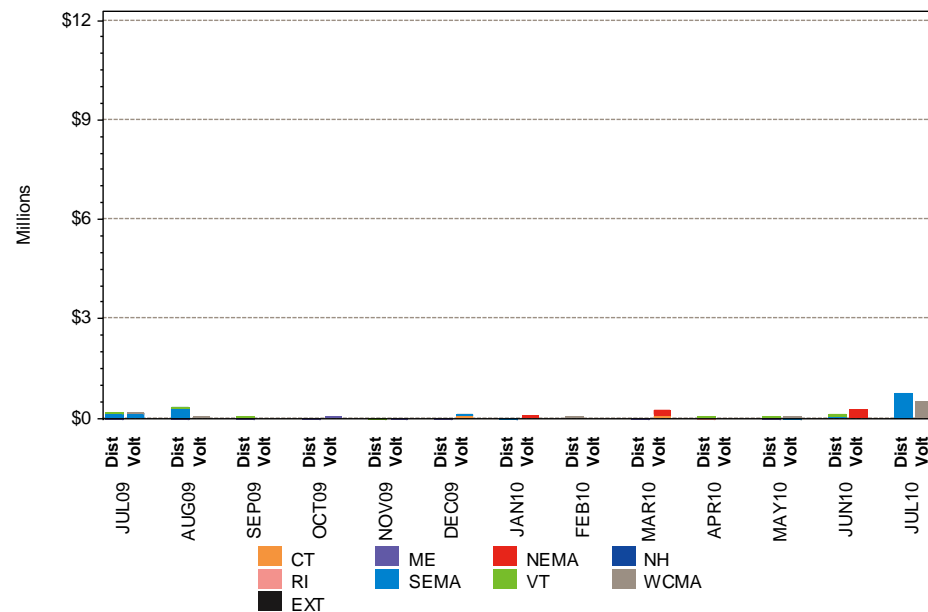


# RT NCPC Payments by Type and Location

## First and Second Contingency Payments

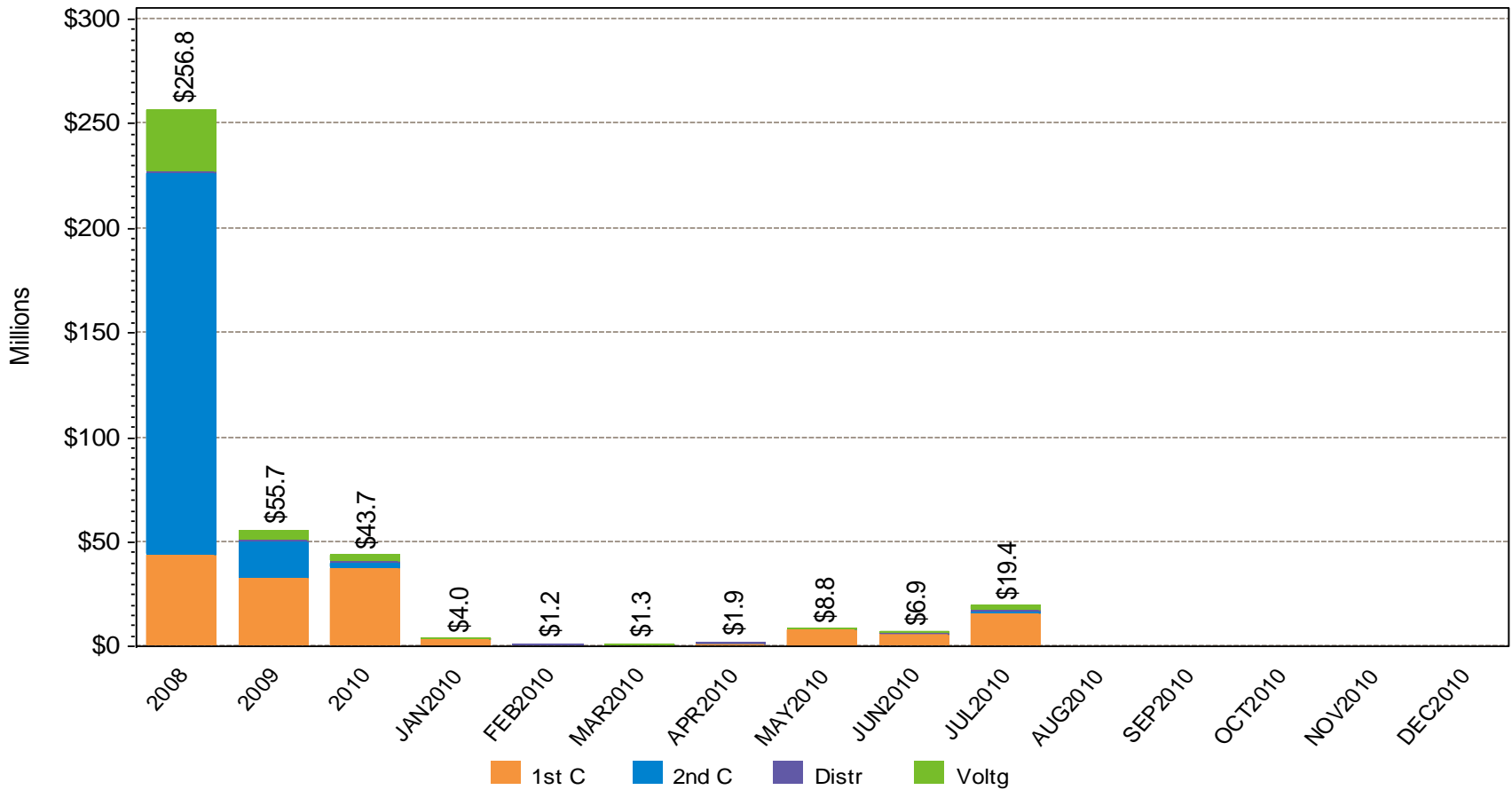


## Voltage and Distribution Payments



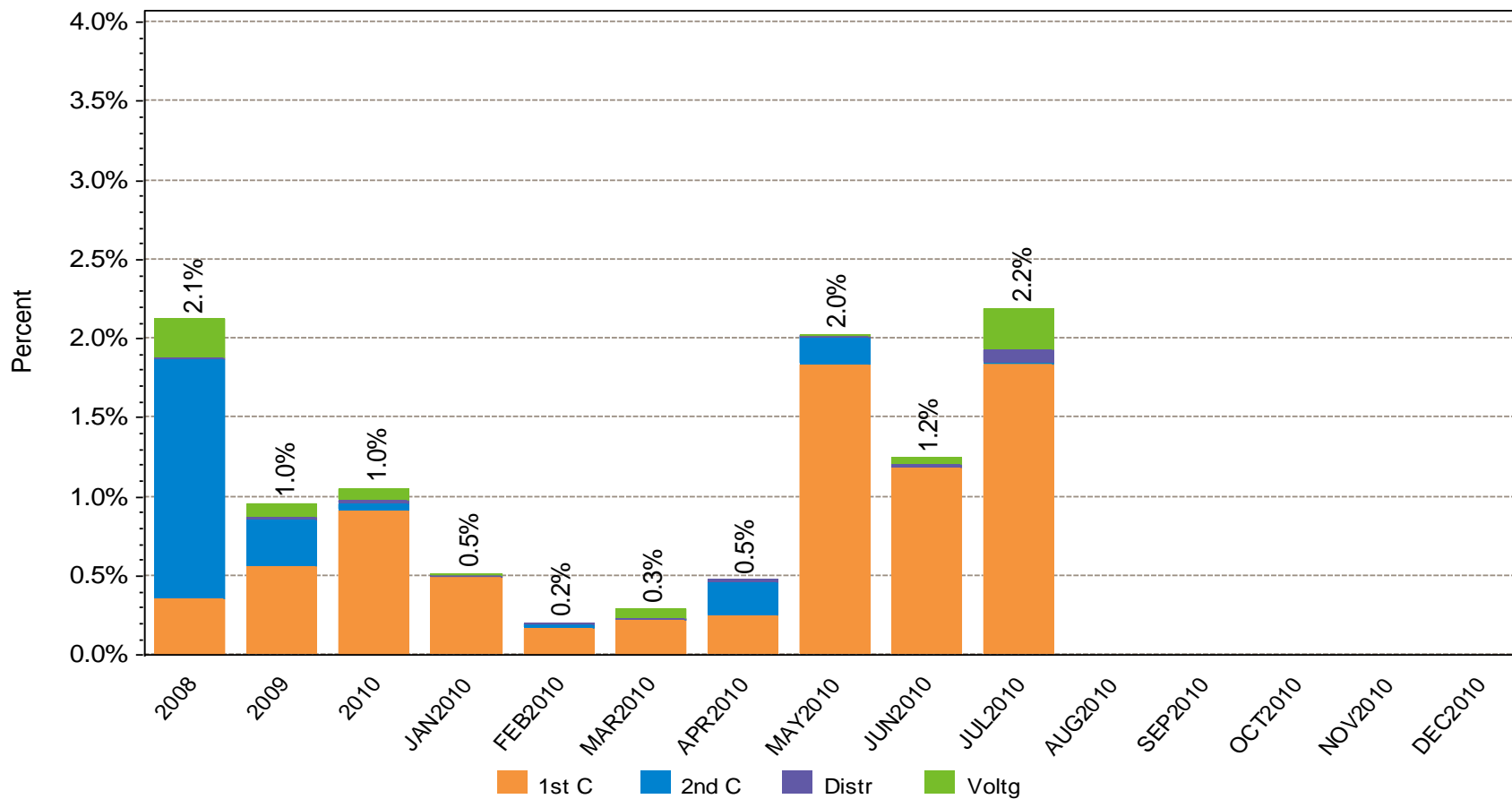
# NCPC Payments by Type

Payments by Type of NCPC



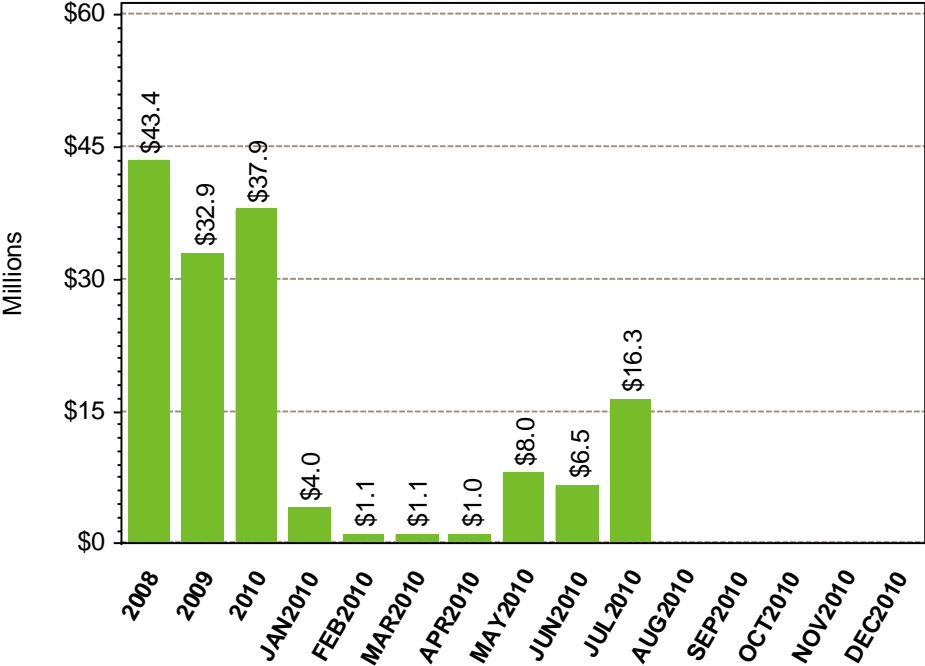
# NCPC Payments by Percent of Energy Market

NCPC By Type as Percent of Energy Market

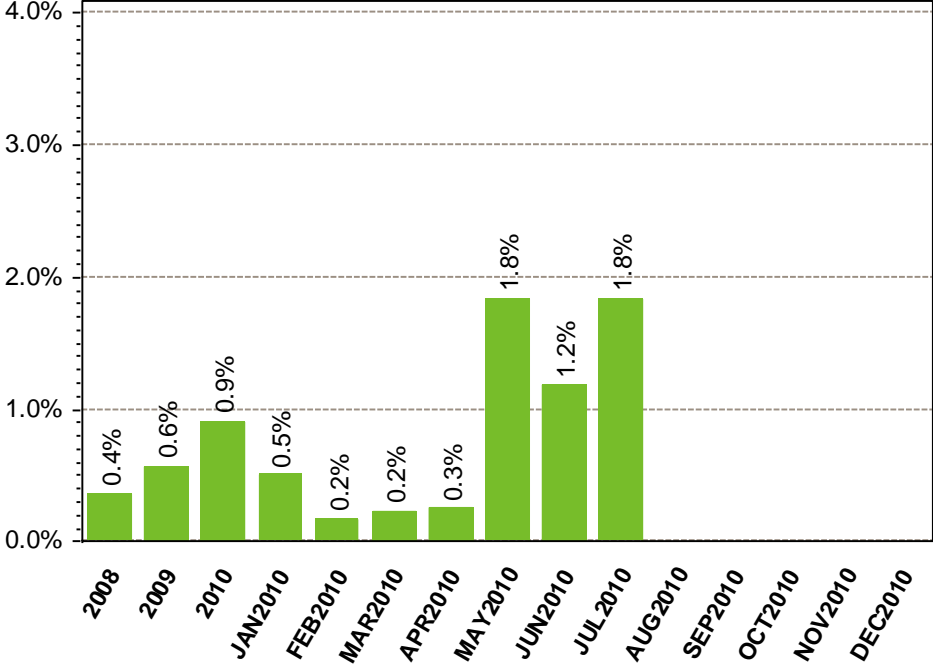


# First Contingency NCPC Payments

Value of Payments



% of Energy Market Value

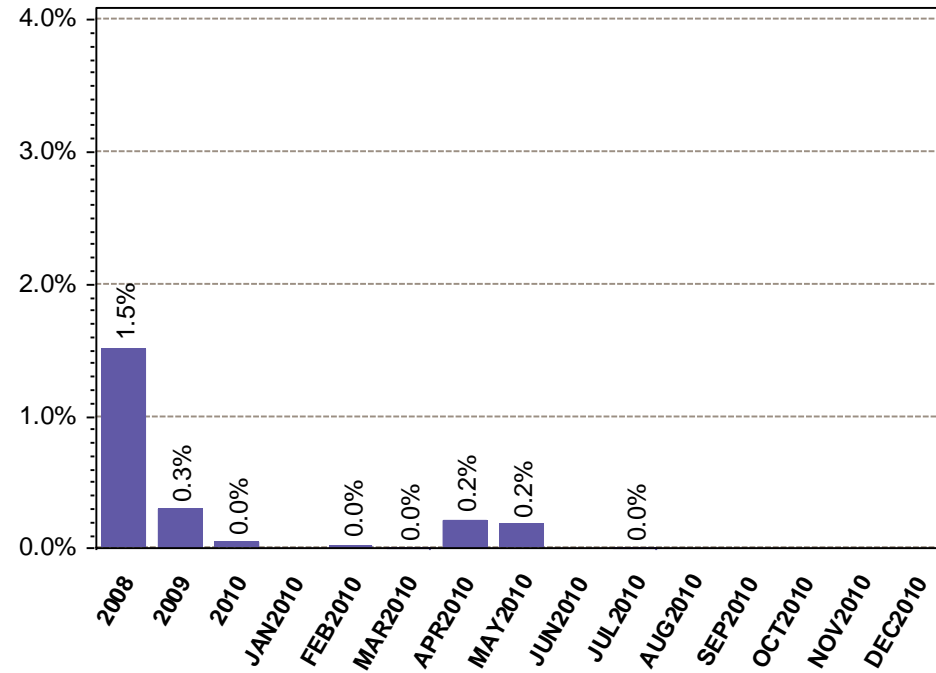
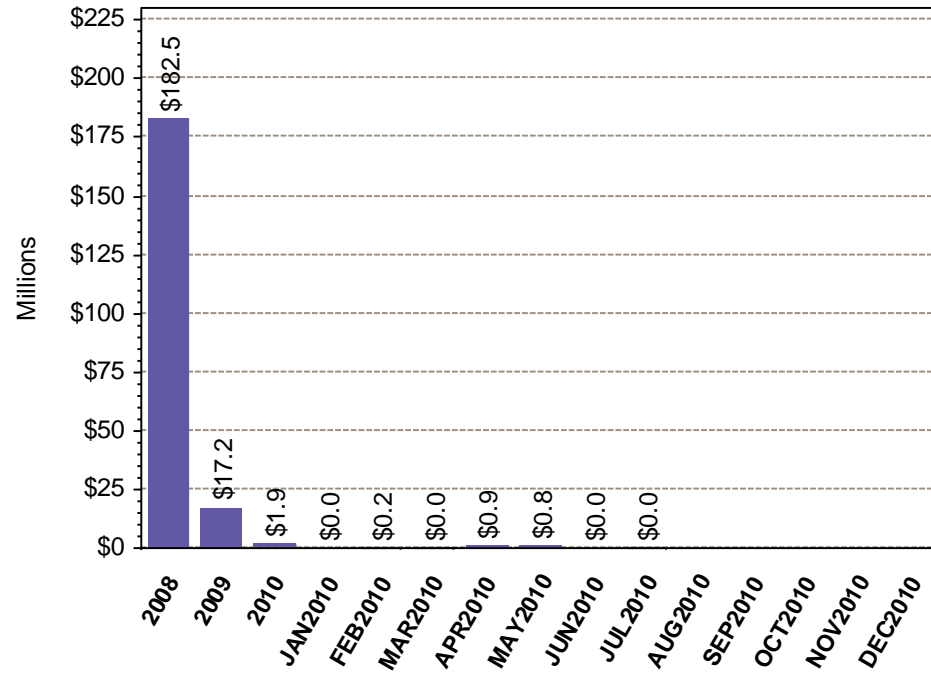


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

# Second Contingency NCPC Payments

Value of Payments

% of Energy Market Value

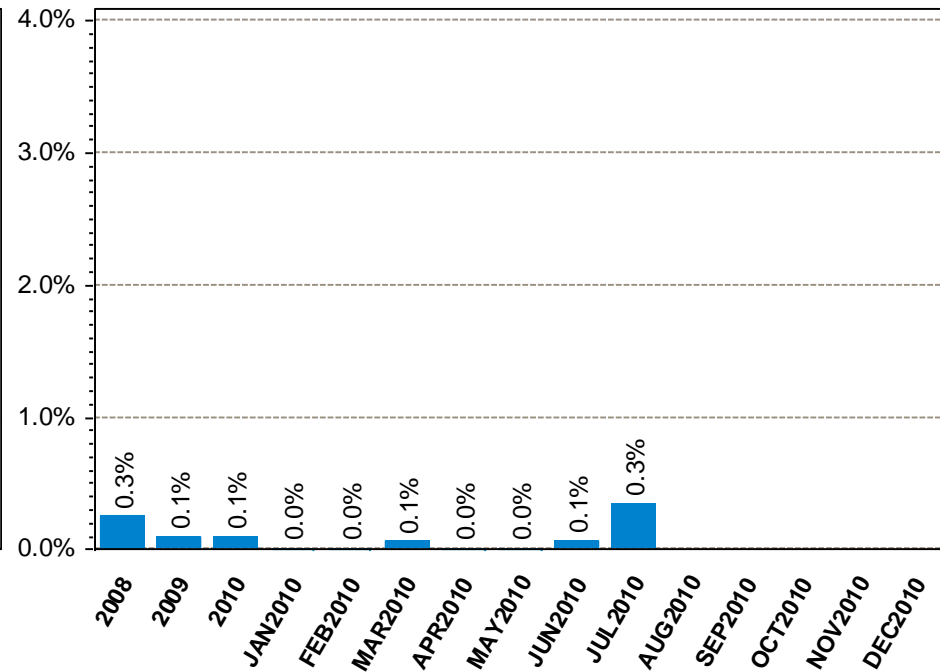
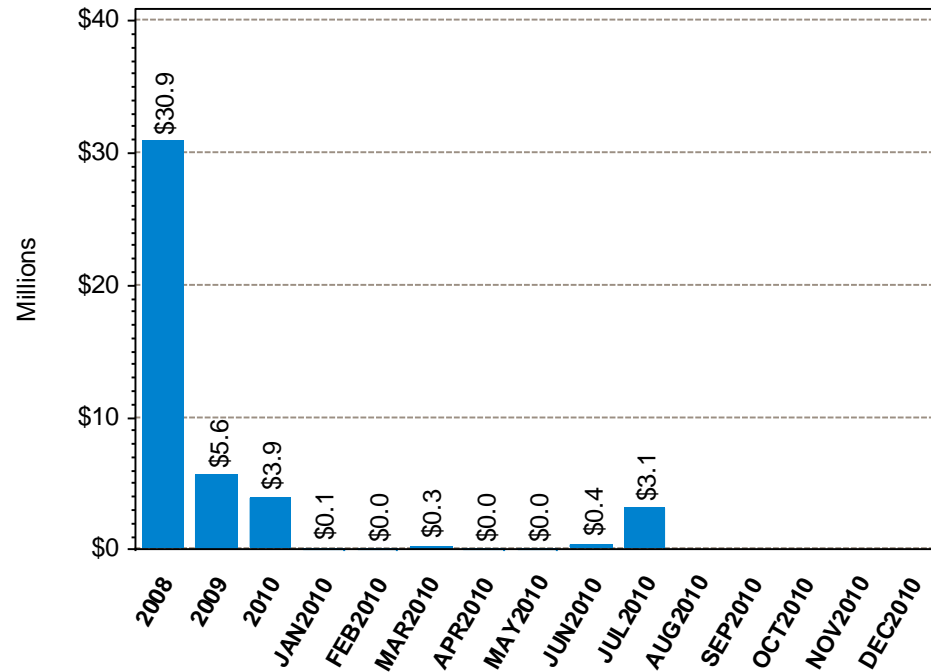


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

# Voltage and Distribution NCPC Payments

Value of Payments

% of Energy Market Value



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

# DA vs. RT Pricing

The following slides outline

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total inc's and dec's
- Self-schedules
- DA vs. RT net interchange
- Delisted capacity

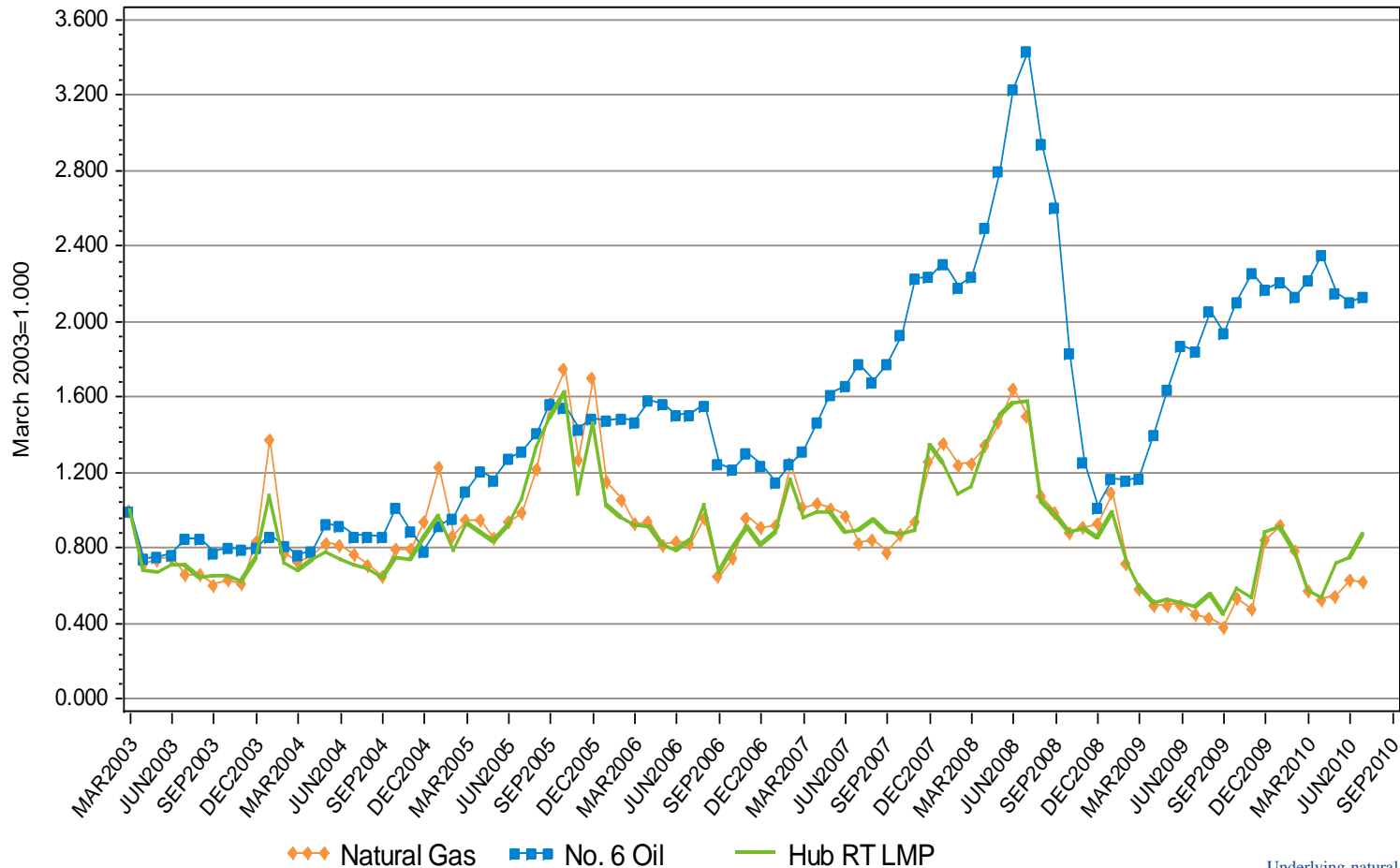
# DA vs. RT LMPs (\$/MWh)

## Arithmetic Average

Year 2008	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$79.85	\$84.85	\$76.13	\$79.22	\$81.07	\$79.33	\$82.73	\$81.31	\$80.64
Real-Time	\$80.49	\$83.56	\$75.60	\$79.52	\$81.17	\$79.62	\$81.56	\$81.41	\$80.75
RT Delta %	0.8%	-1.5%	-0.7%	0.4%	0.1%	0.4%	-1.4%	0.1%	0.1%
Year 2009	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$41.44	\$42.73	\$39.60	\$40.85	\$41.57	\$41.13	\$41.70	\$41.89	\$41.52
Real-Time	\$41.78	\$42.89	\$39.97	\$41.32	\$42.06	\$41.57	\$42.03	\$42.33	\$42.00
RT Delta %	0.8%	0.4%	1.0%	1.1%	1.2%	1.1%	0.8%	1.1%	1.1%

July-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$32.67	\$35.43	\$30.71	\$32.19	\$32.99	\$32.63	\$33.00	\$33.35	\$33.02
Real-Time	\$33.27	\$34.73	\$31.24	\$32.78	\$33.64	\$33.23	\$33.62	\$33.81	\$33.53
RT Delta %	1.8%	-2.0%	1.7%	1.8%	2.0%	1.8%	1.9%	1.4%	1.5%
July-10	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$60.00	\$63.88	\$58.24	\$60.32	\$62.58	\$60.01	\$60.12	\$62.33	\$61.05
Real-Time	\$58.99	\$61.23	\$56.66	\$58.96	\$60.82	\$58.76	\$59.27	\$60.94	\$59.72
RT Delta %	-1.7%	-4.2%	-2.7%	-2.2%	-2.8%	-2.1%	-1.4%	-2.2%	-2.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	83.7%	80.3%	89.6%	87.4%	89.7%	83.9%	82.2%	86.9%	84.9%
Yr over Yr RT	77.3%	76.3%	81.4%	79.9%	80.8%	76.8%	76.3%	80.2%	78.1%

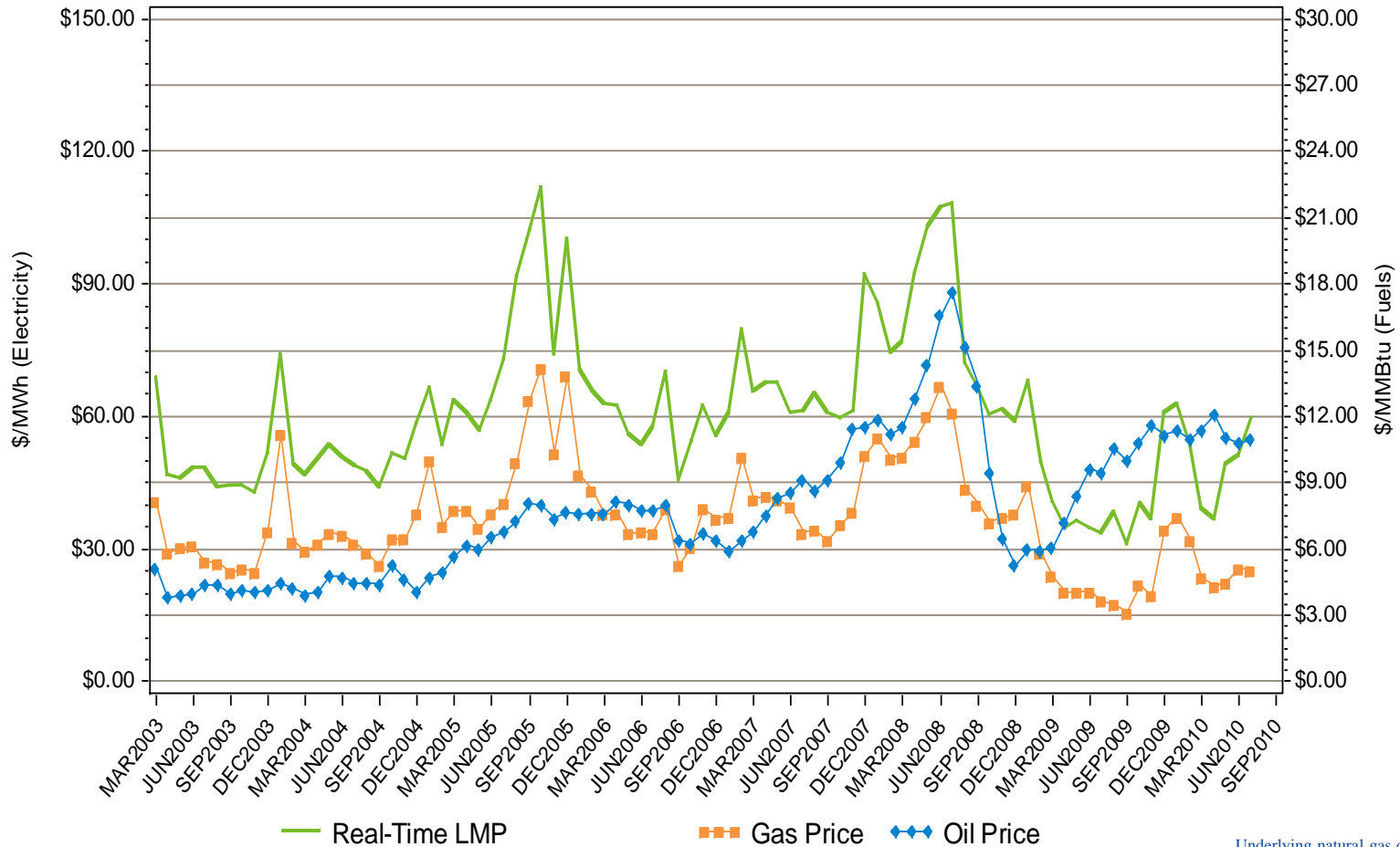
# Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



# Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:



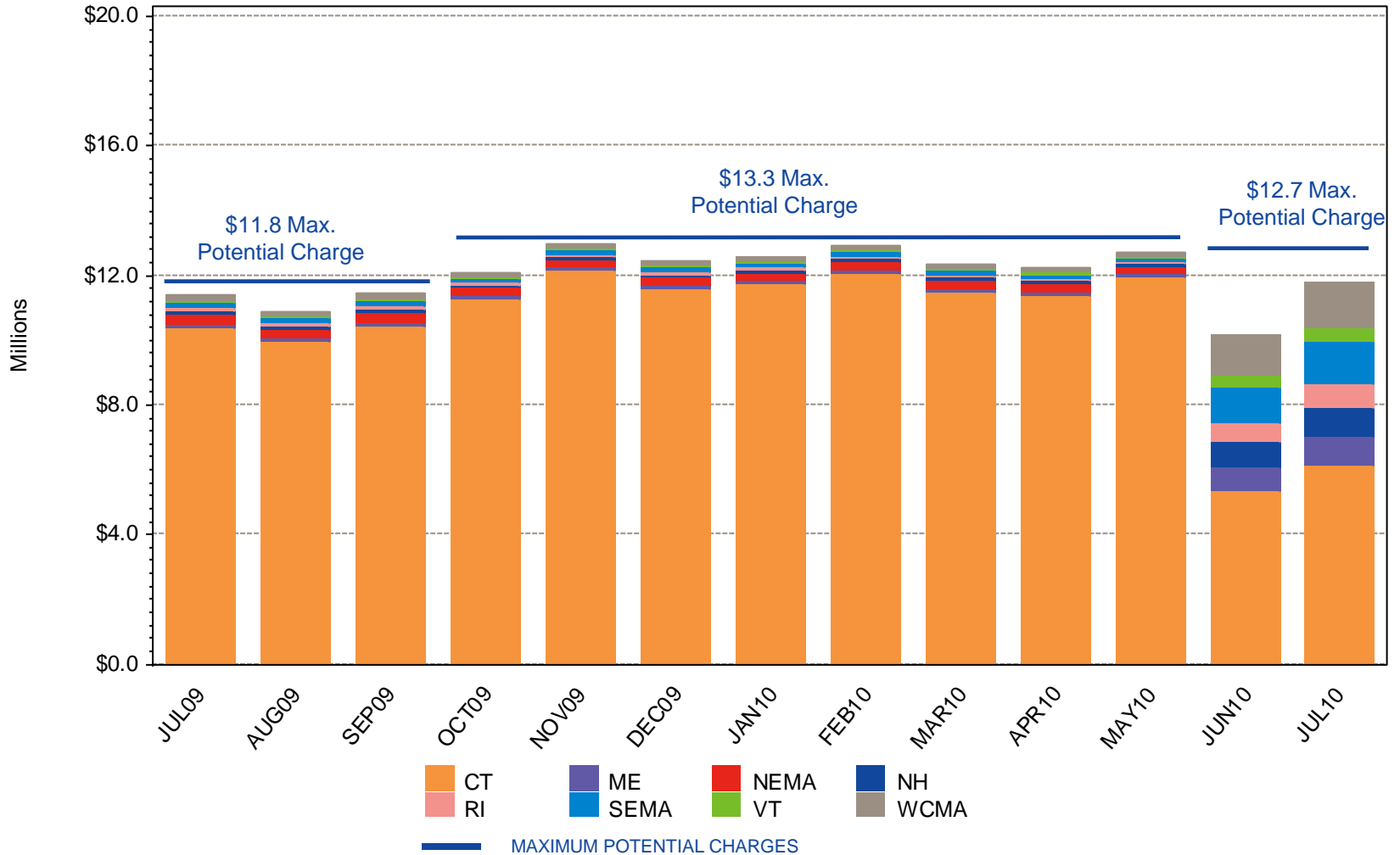
# Reserve Market Results – July 2010

- Maximum potential Forward Reserve Market payments of \$12.7M were reduced by credit reductions of \$354K, failure-to-reserve penalties of \$531K and failure-to-activate penalties of \$0, resulting in a net payout of \$11.8M or 93% of maximum
  - Rest of System: \$1.04M/\$1.16M (90%)
  - Southwest Connecticut: \$3.64M/\$3.78M (96%)
  - Connecticut: \$7.11M/\$7.74M (92%)
  - NEMA: n/a
- \$1.6M in total Real-Time credits were reduced by \$255K in Forward Reserve Energy Obligation Charges for a net of \$1.4M in Real-Time Reserve payments
  - Rest of System: 108 hours, \$922K
  - Southwest Connecticut: 108 hours, \$274K
  - Connecticut: 108 hours, \$138K
  - NEMA: 108 hours, \$53K
- The system reserve bias factor was used on seven days (July 3, 5, 6, 9, 11, 17, 21) during this period.

\* “Failure to reserve” results in both reductions in credits and penalties in the Locational Forward Reserve Market.

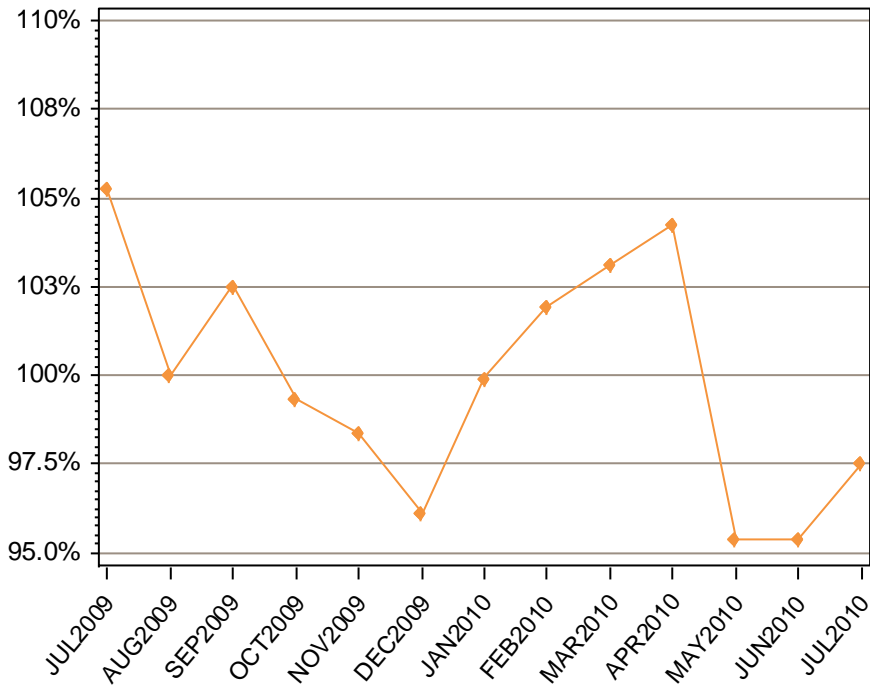
# LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months

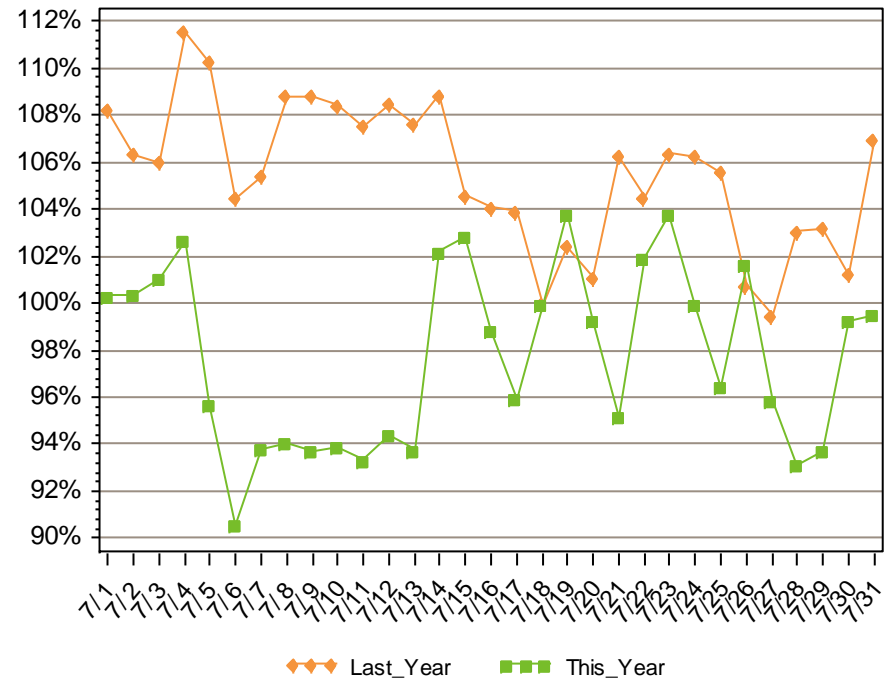


# DA Load Obligation Percent of RT Load Obligation

Monthly, Last 13 Months

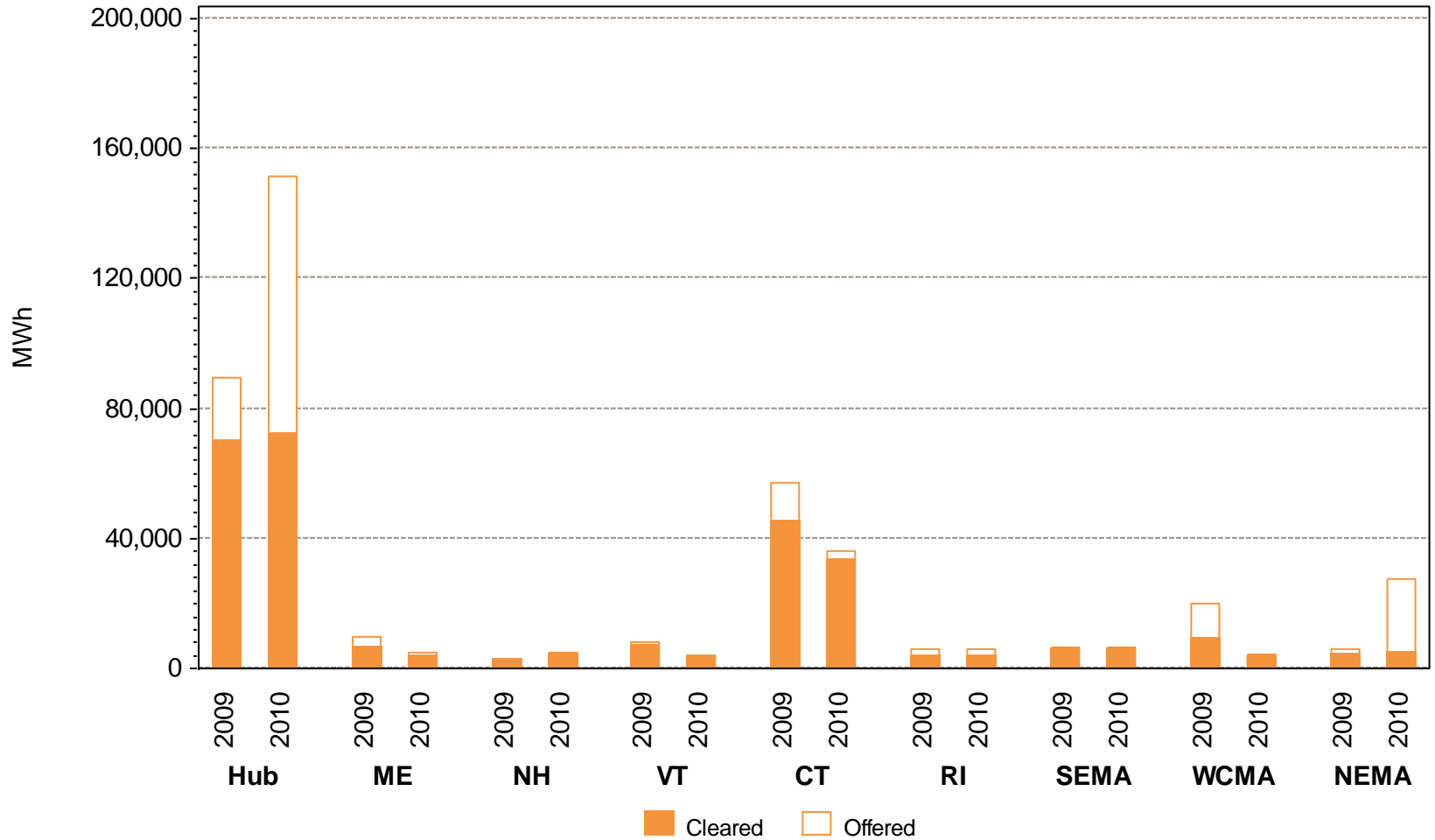


Daily, This Year vs. Last Year



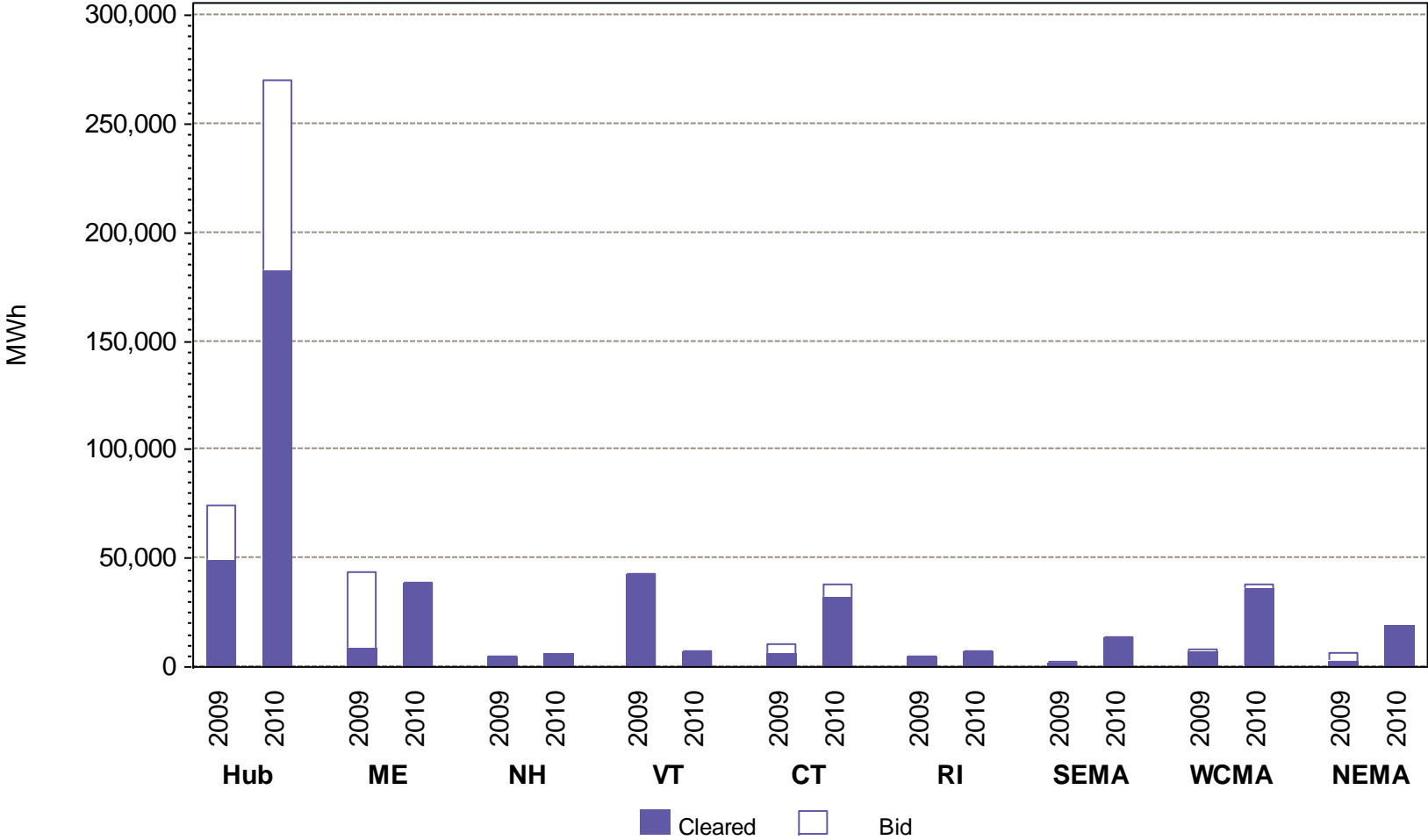
# Zonal Increment Offers and Cleared Amounts

July Monthly Totals by Zone



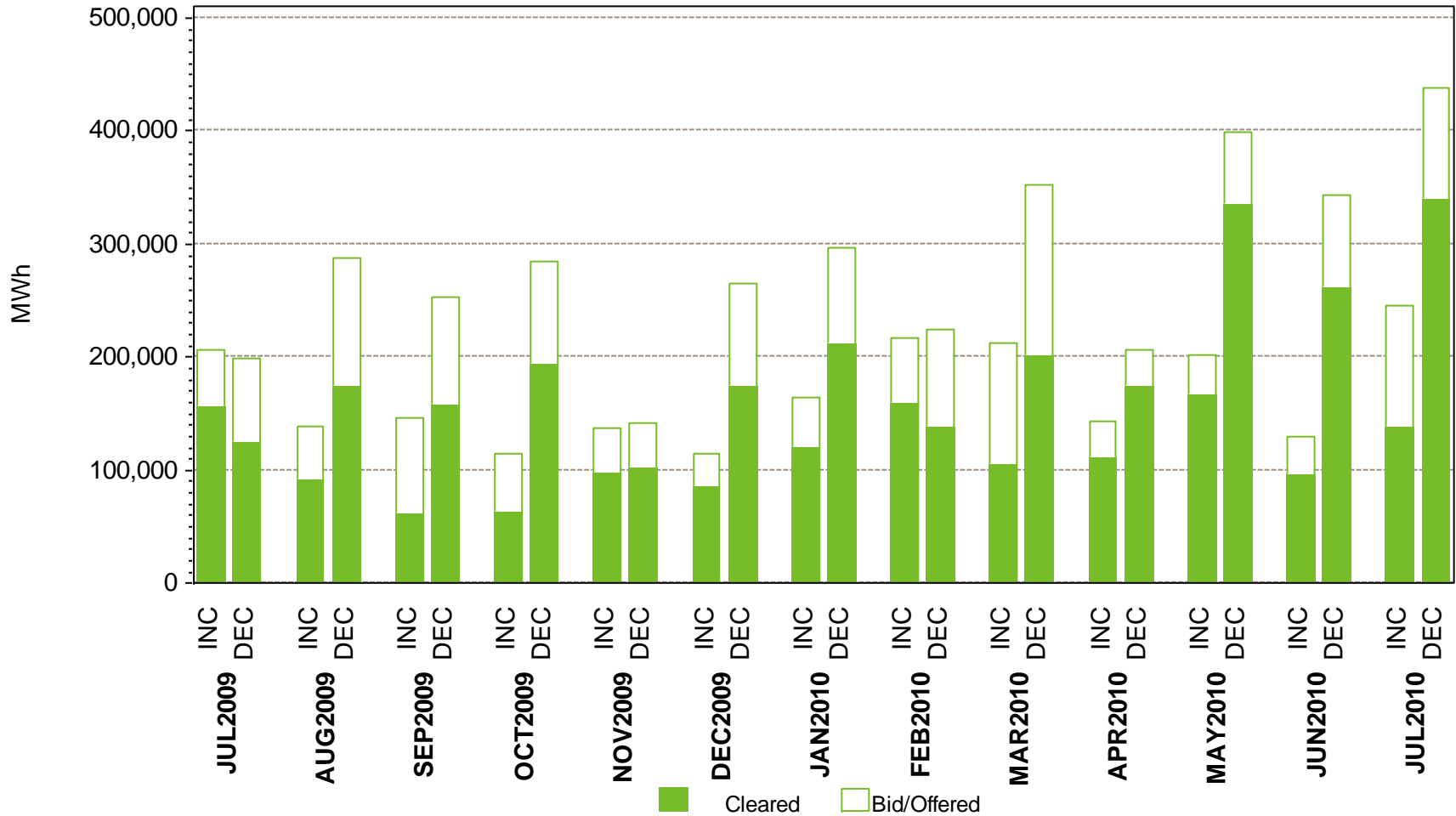
# Zonal Decrement Bids and Cleared Amounts

July Monthly Totals by Zone



# Total Increment Offers and Decrement Bids

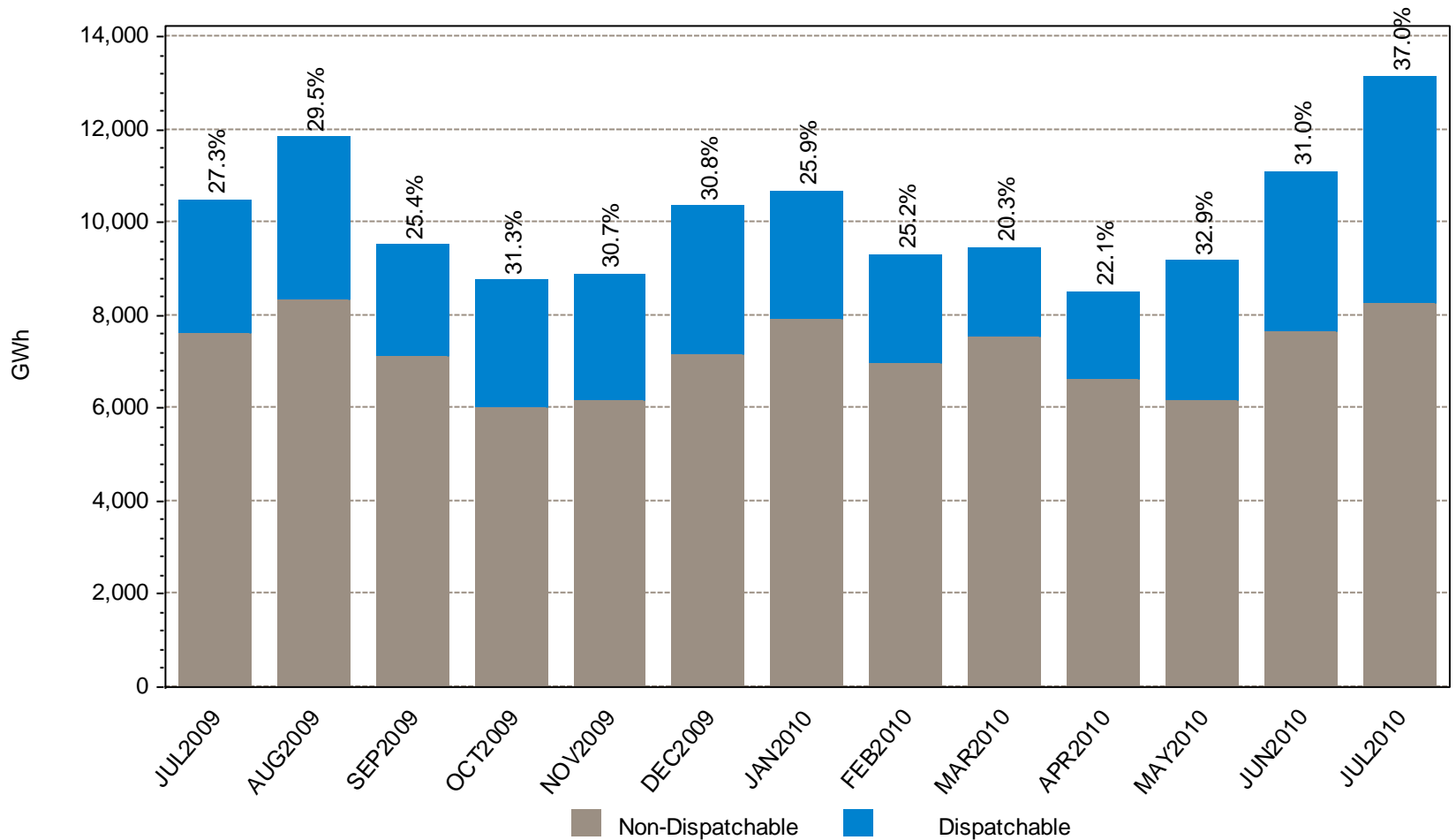
Zonal Level, Last 13 Months



Data excludes nodal offers and bids

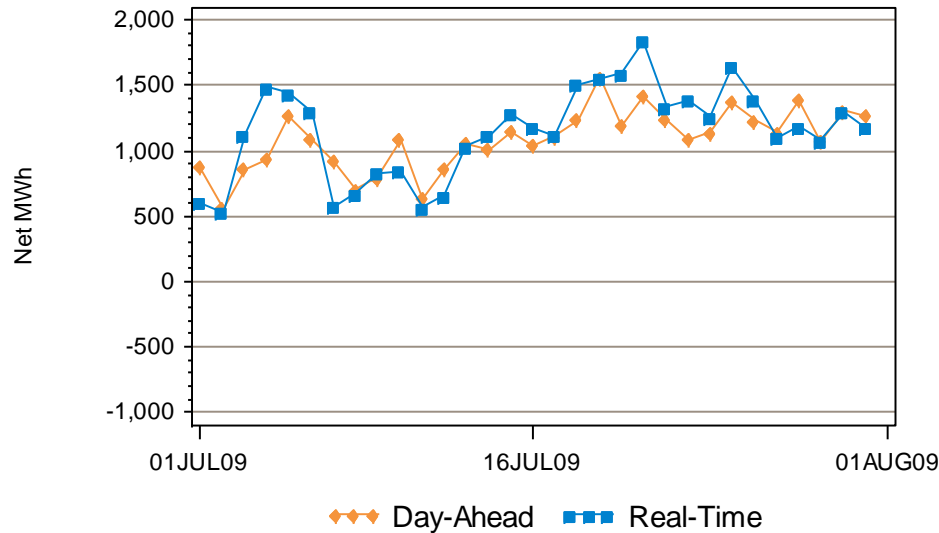
# Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown

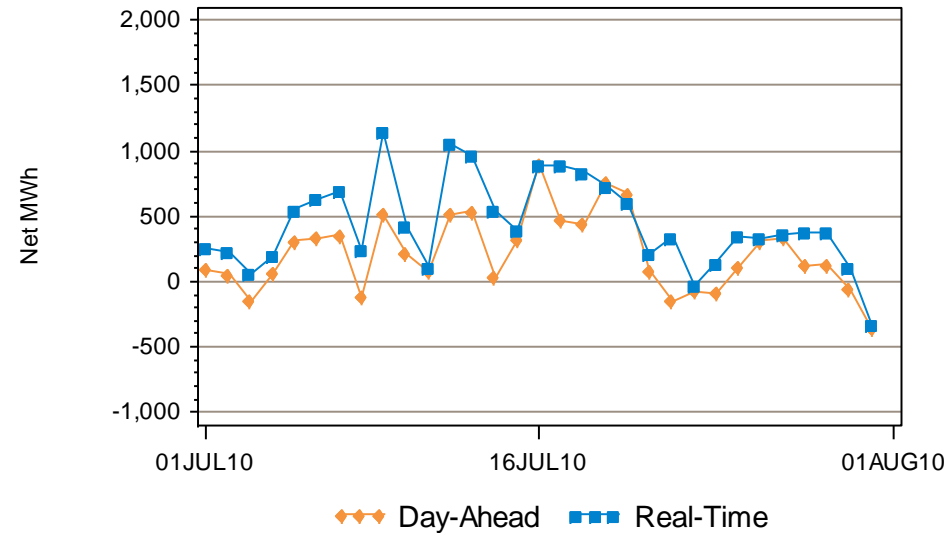


# DA vs. RT Net Interchange July 2010 vs. July 2009

Hourly Average by Day, Last Year



Hourly Average by Day, This Year



Net Interchange is the sum of daily imports minus the sum of daily exports  
Positive values are net imports

# Regional System Plan (RSP)

# RSP10 Report Schedule and Process

- July 20 – Draft RSP10 Report was posted for PAC review and comment
- August 5 – by close of business, all written comments are due from PAC members to [pacmatters@iso-ne.com](mailto:pacmatters@iso-ne.com)
  - Comments must be relevant to information previously presented to PAC and not introduce new scopes of work
  - Original comments will be posted on the ISO website
  - The commenter will be made public unless ISO receives a request to keep the commentator anonymous
- August 12 – PAC discussion of written substantive comments received
  - New comments will be discussed *only as time permits*
- August 12 – PAC discussion of the NEEWS Interstate Reliability Project

# RSP10 Public Meeting: September 16

## Preliminary Agenda

9:30 a.m. – 9:40 a.m.	Welcome
9:40 a.m. – 10:30 a.m.	Presentation of the 2010 RSP and stakeholder discussion (priority will be given to written questions received in advance of the public meeting)
10:30 a.m. – 10:45 a.m.	Break
10:45 a.m. – 12:00 p.m.	Panel #1: State Planning Initiatives and Non-Transmission Alternatives
12:15 p.m. – 1:00 p.m.	Lunch
1:15 p.m. – 1:45 p.m.	Keynote Address: Patricia A. Hoffman, Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy
1:45 p.m. – 3:15 p.m.	Panel #2: Drivers of the Future Grid
3:15 p.m. – 3:30 p.m.	Concluding Comments

# Interregional Planning and Coordination

- Environmental Advisory Group (EAG) teleconference was held July 23 to discuss peak NOx emissions analysis, the draft Emissions Report, and other issues
- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) WebEx is tentatively scheduled for October 6 to discuss interregional production cost studies

# RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

# North Shore Upgrades – Merrimack Valley

Status as of 7/29/10

*Project Benefit: Maintains system reliability for the North Shore area independent of Salem Harbor generation*

Upgrade	Expected In-service	Present Stage
<b>Wakefield Junction/Merrimack Valley</b>		
115 kV Overhead Reconductor (G133E)	Feb-08	4
Reconductor Wakefield Junction - Golden Hills Tap 115 kV	Sep-08	4
30 MVAR 115 kV Capacitor at Revere	Oct-08	4
Wakefield Junction Substation	Nov-09	4
Loop 345 kV and 115 kV lines into Wakefield Substation	Nov-09	4
Retirement of Golden Hills Substation	Apr-10	4
Add parallel 115 kV cable in Mystic-Everett line	Oct-10	2
Add King Street - W. Amesbury 115 kV line	Mar-11	2
Sandy Pond 345 kV Breakers	Jun-12	2
Reconductor Overhead portion of Mystic-Everett 115 kV line	Jun-12	2
Replace Salem-Railyard Cables	Oct-13	2

- Received Reliability Committee (RC) recommendation for I.3.9 approval on 3/27/08
- Final costs presented at 11/19/08 PAC meeting and at 12/18/08 RC meeting (for future vote)
- Transmission Cost Allocation (TCA) application presented at special stakeholder meeting on 1/29/09
- TCA recommended for approval by RC at March 2009 meeting

# Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 7/29/10

*Project Benefit: Improves system reliability for the Lower SEMA area independent of area generation*

Upgrade	Expected In-service	Present Stage
Expand the Carver substation	Dec-12	1
Build new 345 kV line from Carver to new Service Road substation near intersection with the #115 line	Dec-12	1
New Service Road substation with 345-115 kV autotransformer and 3-breaker 115 kV ring bus	Dec-12	1
Build new 115 kV line from Canal to Barnstable	Dec-12	1
Upgrade the D21 line from Bell Rock to High Hill	Dec-12	1
342/322 DCT Separation	Dec-12	1

- ISO I.3.9 approval on 11/5/09
- Siting application scheduled to be filed late summer 2010
- Full status update (needs, preferred solution, needs reassessment) given at 4/27/10 PAC
- Draft solutions report posted 6/21/10; final needs report posted 6/21/10

# Maine Power Reliability Program (MPRP)

Status as of 7/29/10

*Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine*

Upgrade	Expected In-service	Present Stage
New 345 kV Line Construction (Orrington-Albion Road, Albion Road-Coopers Mills, Coopers Mills-Larrabee Road, Larrabee Road-Surowiec), (Surowiec-Raven Farm, South Gorham-Maguire Road, Maguire Road-Three Rivers)	2012	1
New 115 kV Line Construction (Orrington-Coopers Mills, Coopers Mills-Highland, Larrabee Road-Middle Street, Middle Street-Lewiston Lower, Larrabee Road-Livermore Falls, Livermore Falls-Rumford IP, Raven Farm-East Deering, East Deering-Cape, alter Section 212 to become Larrabee Road-Monmouth Substation and Monmouth Substation-Bowman Street, alter Section 86 to become Bucksport-Belfast and Belfast-Lincolntonville)	2012	1
Modify Spring Street substation to create a ring bus. Remove Browns Crossing substation. Reterminate lines at Maine Yankee substation. Loop Section 375 Buxton-Maine Yankee into Surowiec. Transfer existing 115 kV lines from Gulf Island to Larrabee Road substation.	2012	1
New 115 kV Capacitors (10 MVAR at Epping, 10 MVAR at Trenton). New 34.5 kV Capacitor (10.8 MVAR at Belfast)	2012	1
Separation of Double Circuit Towers (345 Kennebec River Crossing 375/377, 345 kV Maine Yankee 375/392, 115 kV Bucksport 65/205)	2012	1

- ISO I.3.9 approval on 7/31/08. ISO I.3.9 approval on 2/26/09 for project revisions
- TCA application presented at special stakeholder meeting on 1/29/09. RC vote on 5/19/09 to recommend approval failed with 64.36% in favor
- TCA determination letter sent on 1/29/10
- Maine PUC issued an order approving most of the projection on 6/10/10

# Vermont Southern Loop Project

Status as of 7/29/10

*Project Benefit: Improves Vermont and New England reliability by addressing the regional issues regarding the loss of the Coolidge – Vermont Yankee (340) 345 kV line*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Vermont Yankee – Newfane – Coolidge 345 kV line	Dec-10	3
Vernon 345/115 kV substation	Dec-10	3
Newfane 345/115 kV substation	Dec-10	3
Loop new 345 kV line into Newfane	Dec-10	3
Coolidge 345 kV substation expansion	Dec-10	3

- ISO I.3.9 approval on 10/1/08
- RC voted to recommend TCA approval to the ISO on 2/24/09
- Construction ahead of original schedule

# New England East-West Solution (NEEWS)

Status as of 7/29/10

*Plan Benefit: Improve New England reliability by increasing transfer limits of three critical interfaces and by eliminating future Springfield, MA and Rhode Island criteria violations*

<b>Sample Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Interstate Reliability Project (IRP)	2013	1
Greater Springfield Reliability Project (GSRP)	2013	1
Central Connecticut East-West Reliability Project (CCRP)	2013	1
Rhode Island Reliability Project (RIRP)	2012	1

- Final “Needs” report posted (both redacted and secured versions)
- Final “Options” report posted (both redacted and secured versions)
- NEEWS preferred alternatives presented at 5/19/08 PAC meeting
- Received ISO I.3.9 approval 9/22/08
- Reaffirmed need for RIRP and GSRP at 6/17/09 PAC meeting
- IRP scheduled for discussion at 8/12/10 PAC meeting
- Need for CCRP under study

# Transmission Siting Update

- New England East-West Solution
  - ISO involvement in RI siting for RIRP complete
    - RI PUC issued draft approval
  - Siting application filed with MA and CT for Springfield portion in October 2008
    - Springfield – CT
      - CT Siting Council approved entire project with the Manchester – Meekville Junction Variation (separate the 395 3-terminal line into 2 separate lines)
    - Springfield – MA
      - Preliminary bench decision supports need but some routing/EMF issues remain

# Transmission Siting Update, *cont.*

- Vermont Southern Loop Project
  - Project filed with Vermont Public Service Board in November 2007
  - Public Service Board approved on 2/11/09
- Maine Power Reliability Program
  - Project filed with the Maine Public Utility Commission on 7/1/08
  - Maine PUC approved most of the project on 6/10/10
  - Hearings continue on some portions of the project (Lewiston Loop, Three Rivers, Surowiec-Raven Farm)
  - Proposed Plan Applications and TCAs need to be revised to reflect the new version of the project

# Operable Capacity Analysis

# Summer/Fall 2010 Operable Capacity Analysis (MW)

	September-10 <sup>2</sup> 50/50 Forecast (Reference Load)	September-10 <sup>2</sup> 90/10 Forecast (Extreme Load)
Generator Capacity Supply Obligation <sup>1</sup>	30,042	SAME
External Node Available capacity	342	SAME
Non Commercial Supply	0	SAME
Planned and other known outage MW <sup>4</sup>	1,540	SAME
Allowance for Unplanned Outages	2,100	SAME
Generation at Risk Due to Gas Supply	0	SAME
Net Capacity <sup>4</sup>	26,740	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	26,618	28,738 (+2,120)
Reserve Requirement	1,800	SAME
Operable Capacity Required	28,418	30,538 (+2,120)
Operable Capacity Margin <sup>4</sup>	(1,680)	(3,800) (-2,120)

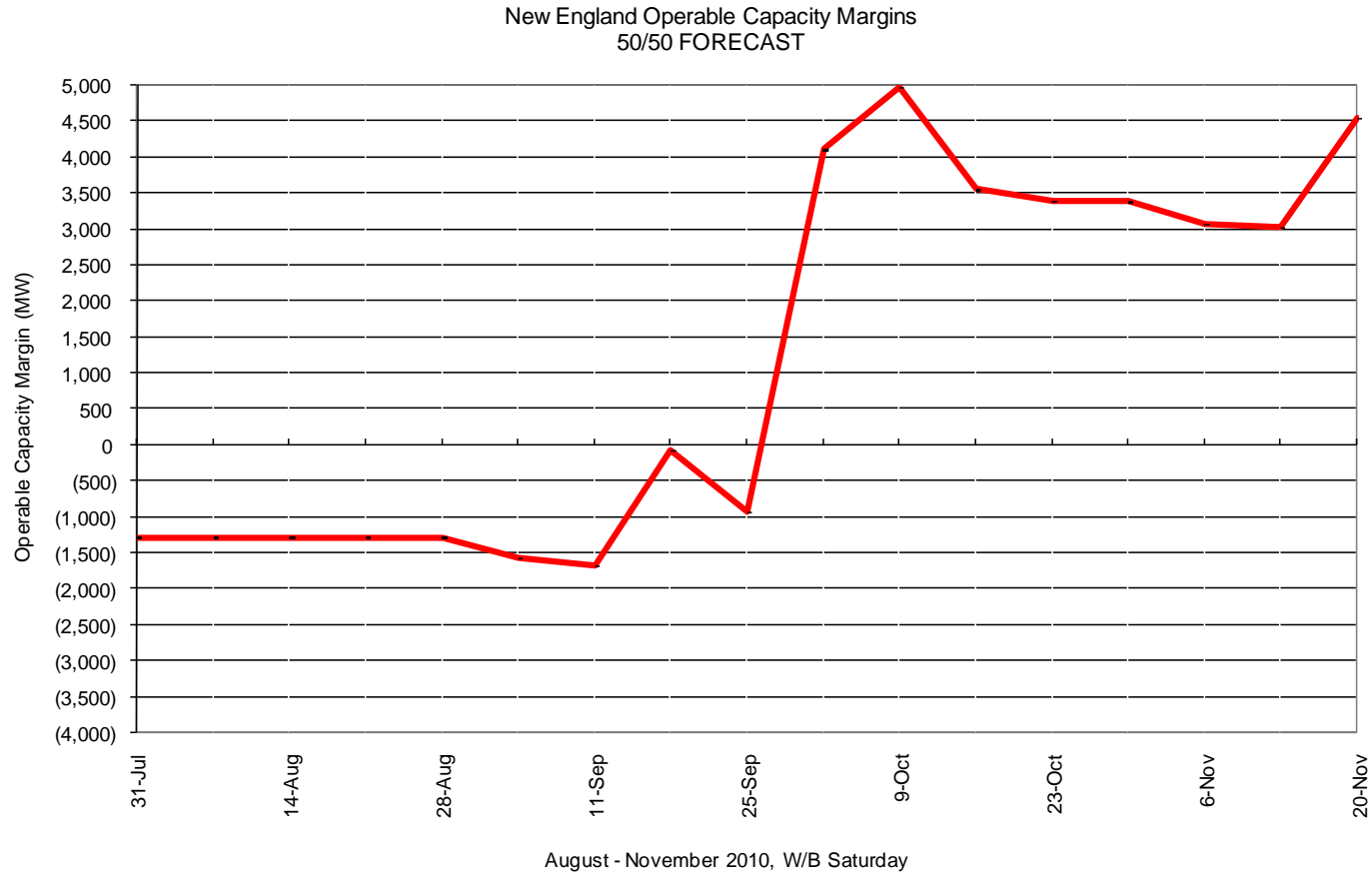
<sup>1</sup> Generator Capacity Supply Obligation is based on data as of July 29, 2010 and does not include Capacity Supply Obligations associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

<sup>2</sup> Based on week with lowest Operable Capacity Margin, week beginning September 11<sup>th</sup>.

<sup>3</sup> Rounded to the nearest hundred.

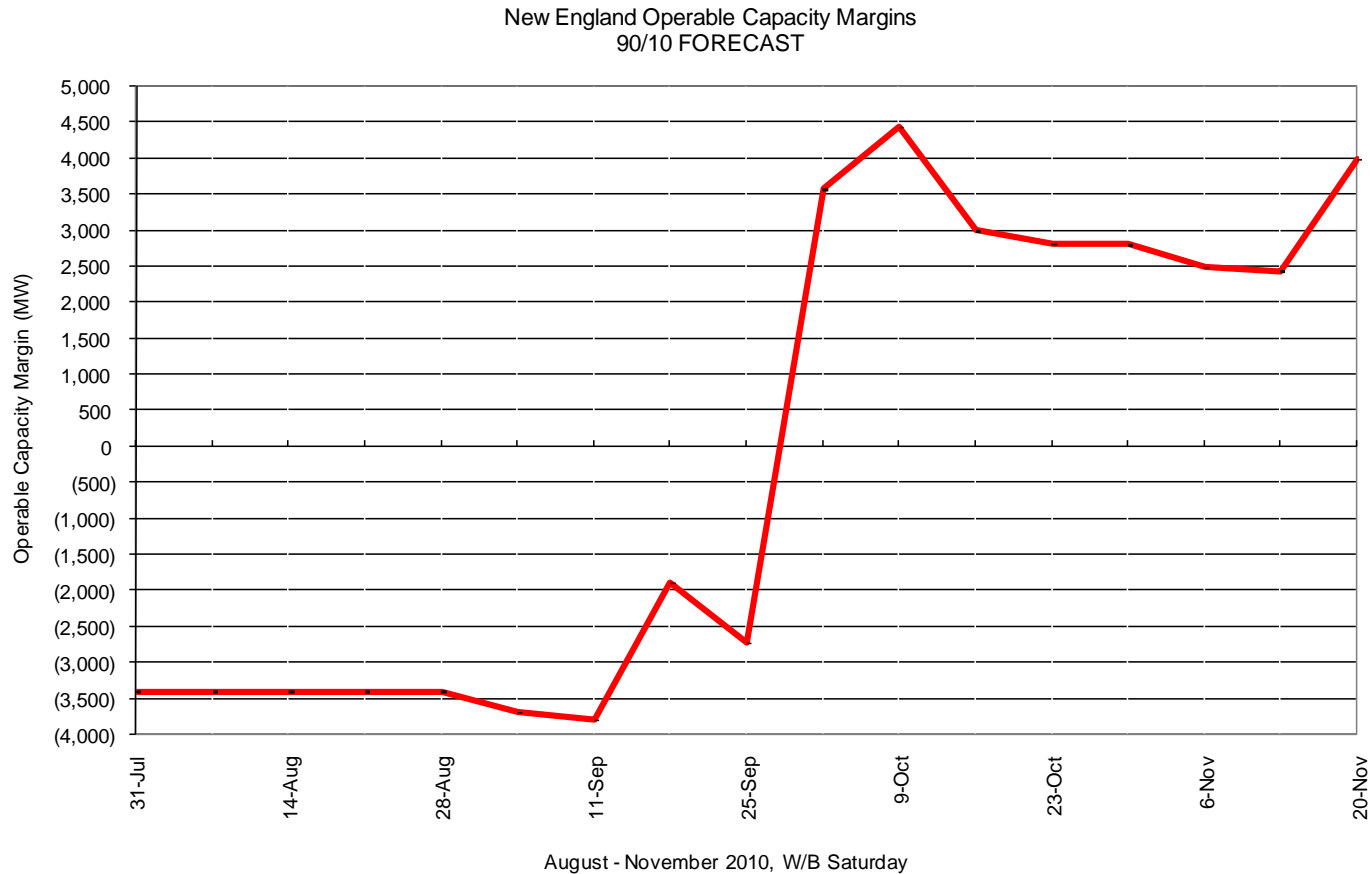
<sup>4</sup> Rounded to the nearest ten

# Summer/Fall 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)



Note: Based on data as of July 29, 2010. Does not include Settlement Only Generators and Active Demand Response.

# Summer/Fall 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)



Note: Based on data as of July 29, 2010. Does not include Settlement Only Generators and Active Demand Response.

# Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and Resources with a CSO prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 <sup>1</sup> 600 <sup>2</sup>
2	Dispatch real time Demand Resources.	670 <sup>3</sup>
3	Voluntary Load Curtailment of Market Participants’ facilities.	40
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-Control-Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	130 <sup>4</sup> 520 <sup>3</sup>
7	Request generating resources not subject to a Capacity Supply Obligation to voluntarily provide energy for reliability purposes	0
8	Voltage Reduction requiring < 10 minutes	270 <sup>4</sup>
9	Voluntary Load Curtailment by Large Industrial and Commercial Customers. Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.	200 <sup>2</sup> 5

# Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
10	Radio and TV Appeal	200
11	Request State Governors to Reinforce Power Warning Appeals.	100
Total		3,735

## Based on results of the April Bilateral and Reconfiguration auctions for June CSO

### NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software. Reserve Margin gross-ups not included and derate not applied.
4. The MW values are based on a 26,618 MW system load and the most recent voltage reduction test % achieved.

# Appendix

# Summer/Fall 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS															
July 30, 2010 - 50/50 FORECAST															
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August.															
STUDY WEEK (Week Beginning, Saturday)	OPCAP SUPPLY							LOAD OBLIGATIONS			OPCAP MARGINS				
	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	PLANNED and other KNOWN OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMEN T MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
07/31/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/07/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/14/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/21/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/28/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
09/04/2010	30,042	342	0	1,440	2,100	0	26,842	26,618	1,800	28,418	(1,580)	520	(1,060)	640	(420)
<b>09/11/2010</b>	<b>30,042</b>	<b>342</b>	<b>0</b>	<b>1,540</b>	<b>2,100</b>	<b>0</b>	<b>26,742</b>	<b>26,618</b>	<b>1,800</b>	<b>28,418</b>	<b>(1,680)</b>	<b>520</b>	<b>(1,160)</b>	<b>640</b>	<b>(520)</b>
09/18/2010	30,042	342	0	3,840	2,100	0	24,442	22,722	1,800	24,522	(80)	520	440	640	1,080
09/25/2010	30,196	300	0	4,200	2,800	0	23,500	22,632	1,800	24,432	(930)	520	(410)	640	230
10/02/2010	30,196	300	0	5,000	2,800	0	22,700	16,793	1,800	18,593	4,110	520	4,630	640	5,270
10/09/2010	30,196	300	0	4,100	2,800	0	23,600	16,829	1,800	18,629	4,970	520	5,490	640	6,130
10/16/2010	30,196	300	0	4,600	2,800	0	23,100	17,748	1,800	19,548	3,550	520	4,070	640	4,710
10/23/2010	30,196	300	0	4,400	2,800	0	23,300	18,110	1,800	19,910	3,390	520	3,910	640	400
10/30/2010	30,196	300	0	3,400	3,600	0	23,500	18,315	1,800	20,115	3,380	520	3,900	640	400
11/06/2010	30,196	300	0	3,600	3,600	0	23,300	18,430	1,800	20,230	3,070	520	3,590	640	400
11/13/2010	30,196	300	0	3,300	3,600	0	23,600	18,772	1,800	20,572	3,030	520	3,550	640	400
11/20/2010	30,196	300	0	3,000	3,600	0	23,900	17,555	1,800	19,355	4,540	520	5,060	640	400

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011. Does not include Settlement Only Generators.
2. External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011
3. New resources that have not yet acquired a CSO but will become commercial in the future.
4. Allowance for Planned Outages includes planned outages scheduled greater than or equal to 15 days in advance.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
6. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
7. Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
8. Peak Load Exposure per data included in the 2010 CELT Report.
9. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
10. Total Load Obligation per the formula (8 + 9 = 10)
11. Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
12. OP 4 Action 2 Real-time Demand Response not including reserve margin gross-ups and derate applied.
13. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
14. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes. Real Time Emergency Generation is capped at 600MW.
15. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 - 14 = 15). This does not include Emergency Energy Transactions (EETs).

# Summer/Fall 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS															
July 30, 2010 -90/10 FORECAST															
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August.															
STUDY WEEK (Week Beginning, Saturday)	OPCAP SUPPLY							LOAD OBLIGATIONS			OPCAP MARGINS				
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	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
07/31/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/07/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/14/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/21/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/28/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
09/04/2010	30,042	342	0	1,440	2,100	0	26,842	28,738	1,800	30,538	(3,700)	520	(3,180)	640	(2,540)
<b>09/11/2010</b>	<b>30,042</b>	<b>342</b>	<b>0</b>	<b>1,540</b>	<b>2,100</b>	<b>0</b>	<b>26,742</b>	<b>28,738</b>	<b>1,800</b>	<b>30,538</b>	<b>(3,800)</b>	<b>520</b>	<b>(3,280)</b>	<b>640</b>	<b>(2,640)</b>
09/18/2010	30,042	342	0	3,840	2,100	0	24,442	24,538	1,800	26,338	(1,900)	520	(1,380)	640	(740)
09/25/2010	30,196	300	0	4,200	2,800	0	23,500	24,441	1,800	26,241	(2,740)	520	(2,220)	640	(1,580)
10/02/2010	30,196	300	0	5,000	2,800	0	22,700	17,328	1,800	19,128	3,570	520	4,090	640	4,730
10/09/2010	30,196	300	0	4,100	2,800	0	23,600	17,365	1,800	19,165	4,430	520	4,950	640	5,590
10/16/2010	30,196	300	0	4,600	2,800	0	23,100	18,312	1,800	20,112	2,990	520	3,510	640	4,150
10/23/2010	30,196	300	0	4,400	2,800	0	23,300	18,685	1,800	20,485	2,810	520	3,330	640	400
10/30/2010	30,196	300	0	3,400	3,600	0	23,500	18,897	1,800	20,697	2,800	520	3,320	640	400
11/06/2010	30,196	300	0	3,600	3,600	0	23,300	19,015	1,800	20,815	2,480	520	3,000	640	400
11/13/2010	30,196	300	0	3,300	3,600	0	23,600	19,368	1,800	21,168	2,430	520	2,950	640	400
11/20/2010	30,196	300	0	3,000	3,600	0	23,900	18,112	1,800	19,912	3,990	520	4,510	640	400

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